<u>Demonstration of Hydroslotter Technology on New York Stripper Wells</u>

Final Report

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By: Lewis (Skip) Taylor

Hydroslotter Corporation

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Hydroslotter Corporation
10 Valleyview Court
Kleinburg, Ontario
L0J 1C0 Canada

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Abstract

The Stripper Well Consortium (SWC) sponsored this project, Demonstration of Hydroslotter Technology on New York Stripper Wells, to demonstrate an innovative stimulation technology named hydroslotting on marginal producing wells on three important plays in New York State: Onondaga, Medina, and Theresa. Under this project, Hydroslotter Corporation prepared, conducted, and evaluated demonstrations of its proprietary technology on four stripper wells in NY State. This report documents the project. Technical and economic conclusions for hydroslotting technology are made and are generally positive.

Executive Summary

The overall program objective is to demonstrate hydroslotting on three different types of geological formations and four different wellbore environments in New York State. The three geological zones were the Onondaga, Medina, and Theresa formations. Special focus is to be paid to the precision, efficacy, performance, and cost of hydroslotting. The two ultimate objectives of this project were to gain greater acceptance for hydroslotting technology and to understand and decrease the costs of using hydroslotting technology on mature and depleted formations in oil and gas wells.

The demonstration can be categorized into three broad sets of tasks: 1) to analyze each candidate well based on a geological / geo-physical process that includes a review of the gas field in general and in the immediate area in order to identify near-wellbore stress regimes and make recommendations for hydroslotting; 2) plan and demonstrate hydroslotting in different situations that present common challenges for all stimulation techniques; and 3) monitor the wells and make evaluations, conclusions, and recommendations.

Hydroslotting is a method of increasing the productivity of oil, gas and hydro-geological wells that uses a proprietary hydrojet machine to remove drilling-related compression in the near-wellbore zone with a deep incision into the producing formation and re-distribute these support stresses outwards, thereby causing an artificial pressure drop and increased permeability in the near-wellbore zone. The hydroslotting method treats the formation with powdered cyclical re-agents to further clean out this zone.

The raw data for this project was provided by the New York State Museum of Geology (Albany, NY). The data was compiled, organized and presented for analysis by Quest Energy (Buffalo, NY). Several meetings between Hydroslotter geo-scientists and Quest Energy resulted in the creation of a number of mappings, graphical, and spreadsheet presentations that assisted in the formation of hydroslotting reservoir models. The field demonstrations were located in western and upstate NY: two wells in the Medina formation in the town of Alden, Erie County, and in Darien, Genesee County, and two wells in Chautauqua County, in the town of Pomfret, on Onondaga and Theresa formations, were used to demonstrate the technology.

A number of accomplishments were achieved during the course of the project. These are listed below:

- The interim report offered a fresh look at the Onondaga, Medina, and Theresa formations
- Hydroslotter Corporation developed and refined a new universal geo-physical methodology
- We eliminated more inefficiencies in analysis and design than in the hydroslotting procedure
- Hydroslotter encountered and overcame three major procedural engineering impediments
- The work performed under this project directly resulted in design and material improvements

The engineering on all the demonstrations experienced no technical glitches; the Theresa well demonstration required two procedures but otherwise also went smoothly. The perforation aspect of the technology was demonstrated on all wells but not the chemical aspect: instead lease water was used as the working fluid. The design and use of a chemical reagent on the formations in accordance with the patented method was finally disregarded after argument regarding lack of information on the wells, disagreement over the chemical treatment protocol, and financial restrictions.

Actual technological and economic results were mixed. With further experience expected in the future in New York State, it is strongly believed that the productivity and reliability of the technology can increase.

Conclusions and Recommendations

1. Hydroslotting can be commercially viable if several conditions are met.

2. While durability is important for the hydroslotter machine, it is a necessity for the nozzles.

3. It is recommended that new technologies such as hydroslotting be used to enter into the attic gas reserves of the Medina formation.

4. It is recommended that the governmental and regulatory bodies in charge of collection of information set stricter guidelines for reporting requirements.

5. Impediments to the development of this technology include the inefficiencies relating to geological / geo-physical qualification process and hydroslot design, and not the actual procedure.

6. SWC leadership and partnership with industry plays a significant role in encouraging the use of hydroslotting for stripper wells.

7. A critical leadership role for the SWC is to convince the industry and society at large that future gas reserves will be produced from stripper well reservoirs.

Demonstration of Hydroslotter Technology on New York Stripper Wells

Section A: Project Overview

Project Objectives

The primary objective of this project was to test hydroslotter technology on three important New York plays: Onondaga, Medina, and Theresa formations. These formations were chosen because of their development and economic significance for the Appalachian Basin but also because they represent three different types of geologies: carbonates, tight gas sands, and shale gas sands. Tests were to be conducted in Chautauqua, Erie, and Genesee counties, New York.

Originally, the objective was to demonstrate the technology in five (5) different types of wellbore environments, including:

- in a previously completed zone
- near a gas-water contact
- in a by-passed zone of pay
- in a problematic or complicated well
- in a previously fractured zone

When the proposal was formalized and accepted, Hydroslotter was requested to release one of the initiatives and concentrate on the other four. Hydroslotter chose to release the demonstration in a previously hydraulic fractured well. The reason for this choice was because it was left for a future demonstration. We had discovered in early 2005 that hydroslotting in combination with fracturing (or in a fractured zone) offers supplemental benefits that exceed the singular benefits of hydroslotting alone in certain geological formations. A patent was issued regarding this improvement in 2006.

The work was planned into three main stages. The first stage was to select and assess candidate wells using geological and engineering analysis and treatment protocol calculations. The second stage was to conduct hydroslotting treatment procedures according to the objectives above on candidate wells selected for the project. The third stage was to monitor the selected wells and evaluate the effectiveness of the technology application for one year. In general, the four objectives were not difficult to complete and Hydroslotter was able to stay within the budget requirements of the project. This report models the results to show the economic benefits to operators, including reduced payout times, and increased well productivity and longevity.

Project Background

With the advent of high-pressure water-jets in the 1980's, the world oil & gas industry soon figured out that water-jetting abrasive slurry straight through the walls of the casing would cleanly flush out all metal and debris and reach inside the oil-bearing formation and stimulate oil and gas wells better than did standard perforations. Very different from ideas and practices that were forming in the USA, primarily the Russians differentiated near-wellbore damage caused by drilling from compressive stresses caused by drilling, and concluded the latter to have a greater negative influence on near-wellbore permeability. This reality has been virtually ignored in western geo-physical academia. The USSR began developing their water-jetting concept into vertical slotting of the wellbore casing to reverse the negative effects of near-wellbore stress on permeability.

The Russians created a method to deal with these compressive stresses, which was to precisely cut a "door-frame" shaped slice of pre-determined depth and vector through the casing and create a cavity in the hydrocarbon formation to a much greater horizontal depth. Slotting purportedly offered many benefits without the inherent disadvantages of the American methods. After the collapse of the Soviet Union in 1991 and subsequent decline in world oil prices, this new method, which Hydroslotter Corporation coined abrasive hydrojet slotting or "hydroslotting", made no material advancements until we revived the idea and began R&D in early 2001.

Originally the invention had numerous deficiencies. Primarily, the downhole hydroslotting tools were irreparably damaged, frequently and unexpectedly, making the method unreliable and expensive. The problem was that single, short applications routinely destroyed the down-hole tools. The original Russian prototype was virtually hand-made and of rudimentary design and could not hold up to continuous use. Two other problems were that technical documentation was not clear and all the historical field results could not be verified.

We discovered through our extensive theoretical and field research, that hydroslotting is effective in all oil- or gas-bearing formations, but is only superior to other technologies in certain types of rock. From this investigation, we found that our technology counter-intuitively worked better in specific geologies with higher pressures. High pressure formations are generally found in deeper rock formations. This is not a "restriction," but actually a predilection. In fact, being able to grasp where the technology excels best has allowed us to focus on many opportunities. We developed our mathematical models by playing with variables that included using raw data to calculate the reduction of density of the rock, the effects of slotting depths or changing the orientation of the slots, and designing chemical reagents for a variety of scenarios within the same formation interval.

Our research on the tool design was very effective and we made strong inroads. We investigated various metallurgies, electronics, and sub-systems that could potentially be used in our 3rd-gen machines. Many times, research was challenging because we were contemplating things that had never been used before in the oil and gas industry. We were able to make informed decisions about new ideas that would help durability, stabilize working pressure, lengthen application times, and extend service life. Therefore the two main areas we focused on were design of new parts to increase efficiency and reduce wear (abrasion & corrosion), and making all parts stronger by using better metallurgies. We also experimented with multiple perforators to increase the slotting rate without surrendering efficiency or increases in cost or working pressure.

The ultimate goal of the company was to commercialize the technology as quickly as possible in order to have the benefits widely available to the industry and society at large. However, it was apparent that many operators, especially those of marginal wells, had neither the discretionary capital nor the risk profile to invest in a new technology with unproven results. It was a business challenge that widespread acceptance would not occur until hydroslotting could be shown and verified to have worked in various geologies and wellbore environments – the more examples, the better – and could be marketed at a cost-effective price. In the beginning, this caused the company to direct its efforts on acquiring and re-working its own wells to demonstrate the technology, a business plan that was successful because the profits created from increased production continue to this day.

The company pursued the assistance of the SWC to demonstrate the technology to operators in an independent and public forum. The successful application of hydroslotting in this type of forum would provide the credibility to prove that a large number of wells in various formations could benefit from hydroslotting. This could spur the future application of hydroslotter technology on thousands of wells and result in increased supplies of domestic natural gas and petroleum.

A new prototype with increased durability, strength, and additional flexibility needed to be designed and constructed for the demonstration. To do this, we augmented the original Russian creation with North American engineering and superior materials, to create what we called a second-generation, intermediate or hybrid design. The goal was to create a more advanced third-generation prototype that would function properly in various oil and gas geologies and down-hole engineering environments and respond better to the restrictions and limitations of the method.

In the end, Hydroslotter field tested the second-generation design for this SWC project. Technologically the demonstrations were a success, but economic analysis pointed to uncertain or moderate financial returns, which indicate that factors other than efficiency improvements may need to be considered to ensure profitability. Results and analysis of the field tests are described in this report.

Section B: Experimental

Overview of the Hydroslotting Method

Drilling and completion with standard perforation necessarily causes compression of stresses in the formation adjacent the casing (the "near-wellbore zone"), and often also causes damage. Both these factors inhibit or block the flow of fluids between the wellbore and formation. (It is not an indication that compressive stresses do not exist if is not noticeable with strong well production.) One solution to the damage associated with jet perforating is abrasive water jetting or "notching". Notching makes shallow holes in the casing and cement and reaches a little farther into the oil- or gas-bearing rock and avoids the destructive effects of perforations. Abrasive fluid is pumped down the pipe string to the jet body and is directed against the inside of the casing with a nozzle(s), thereby cutting a hole. Returns of the fluid along with debris from the casing, cement, and formation are taken up the wellbore annulus.

Companies researching this method include Halliburton, Schlumberger, Penetrators Canada, Centura Oil, Blast Energy Services, and Tempress Technologies, among others. Historically, the objective of notching is to create clean communication between the wellbore and formation only, so in practice it has always been used as a precursor to hydraulic fracturing or acidization. This is not much different from what was done some 50 years ago when water-jet perforation was invented. In contrast, hydroslotting goes two full steps beyond abrasive jetting with expectations to enhance productivity results on its own.

Hydroslotting is distinct from notching because the water-jets are used for deliberate removal of pressure around the wellbore by adding a vertical component, and deep horizontal excavation to expand the drainage radius. Hydroslotting removes the mechanical compression stresses in the near-wellbore zone, which in turn eliminates the decisive influence they have on productivity. Hydroslotting creates a low-pressure area in the near-wellbore zone, creating an osmotic pressure difference from distant higher pressure areas, allowing fluids to move toward the well. The symmetrical and vertical design of the hydroslot, not the fact that it is made by water jets, is what increases permeability by 20-40 times in the near-wellbore zone. The deeper the horizontal excavation, the greater the drainage area and longer the commercial life of the well. An overview of the scientific principles of the hydroslotting method is discussed in <u>Appendix A: Scientific Principles of Hydroslotting</u>.

In the marketplace, there is no other technology that achieves the objectives of hydroslotting or at the same price. It should be noted that only hydroslotting (and no other technology) transfers near-wellbore damage to the distant tips of slots as a method of maximizing productivity and extending a well's life. It is evident that the marketplace needs better education about how a decrease in near-wellbore pressure causes an inverse boost in porosity, permeability, and productivity.

Hydroslotting System Description

The method for abrasive hydrojet perforating a well uses a standard service rig and a high-pressure pump unit, and requires a small crew and supporting equipment, including a BOP. Safety is the first priority in the operation of a hydroslotting procedure. The objectives of the procedure is to clean out the well to below the pay zone; log the well and correlate production zones; slot the selected intervals; apply the chemical treatment; and return the well to production. For small zones, the process requires one day of work or less, depending on the vertical length of the slotted intervals. Typically, the slotting procedure begins at the bottom of the targeted production zone. The tool is repositioned by raising the tubing for each new slot to be cut. The normal procedure used in hydroslotting a well is found in Appendix B: Typical Hydroslotting Procedure.

The hydroslotter machine is a stand-alone device that is placed in the wellbore at the desired interval(s) on the end of drill or production tubing, and is removed at the end of all hydroslotting procedures. It weighs 160 lbs and is 10.1 feet long. When the operation is ready to begin and the pump pressure is increased to the working level (3000 – 6500 psi at surface), abrasive sand is added. The machine locks itself into place in the wellbore so that it cannot shake, turn, or move vertically, ensuring the cutting activity is smooth and consistent and at the correct interval depth. The machine diverts the abrasive slurry through sets of nozzles pointing directly at the casing, which takes a few minutes to cut through. Once through the casing, the cement bond and the rock formation behind the pipe flush away "like a knife through butter". As the procedure continues, the internal throttle system causes the vertical descent of the nozzles at a speed that is needed to create a slot that is consistently deep and wide at all points.

One important mechanical difference between the hydroslotter machine and the tools of competitors is that the slotting procedure is controlled at the point of engagement and not from the surface. It has been shown that controlling a vertical descent of nozzles from the surface results in an inconsistent cut that resembles "chicken scratch" with no predictability of any vertical depth or vector. A second important difference is the durability of the metallurgies used in the hydroslotter equipment.

Hydroslotter Corporation manufactures all equipment to API Standards and at an ISO 9000 standards compliant facility. Hydroslotter machines are designed for versatility, to exceed the needs of the tasks at hand. Hydroslotter can furnish the equipment with or without certain specialized components that assist the customer in completing the well according to important geological and/or engineering pre-requisites. In addition, Hydroslotter can provide real-time development and recording systems to gather important real-time data about the procedure, the rock formation being hydroslotted, and the well.

Accomplishments

A number of accomplishments were achieved during the course of the project. These are listed below.

1. The interim report offered a fresh look at the Onondaga, Medina, and Theresa formations. In the Report on Geological and Field Data Investigation, attached as Appendix C hereto, reservoir models were created from complex analyses of gas exploitation and log data. Conclusions were able to be made about the Onondaga and Theresa formations, but data was generally insufficient because these formations are not well explored. The following conclusions were able to be made about the three formations:

- All three formations suffer from low pressure, where hydrostatic exceeds reservoir pressure
- Total well production is sourced from less than 50% of the entire Medina reservoir
- Gas production in the Medina could be increased by
  - Primary completion of existing pay zones using hydroslotting
  - Secondary completion by hydraulic fracturing in poor drainage zones even after hydroslotting
  - Selective exploitation of the top part of the Medina that is currently not the choice for gas production (by-passed pay), which contains, on average, 30% of all Medina gas resources, with maximum and minimum ranges from 10 to 70%
  - Drilling of additional new wells in the most prospective zones minimally or not impacted by the drainage of gas from nearby production wells.
- Gas production in the Onondaga could be increased by
  - Hydroslotting where conventional perforating was previously ineffective
- Upper Cambrian Theresa wells can be high producers with hydroslotting

2. Hydroslotter Corporation developed and refined a new universal geo-physical methodology. As presented in Appendix C: Report on Geological and Field Data Investigation, this methodology was able to correctly:

- Describe reservoir characteristics and natural fracture systems
- Determine reservoir permeability, gas saturation, "filtration-capacitor" characteristics
- Define effective thicknesses of gas saturation & filtration, porosity & gas saturation coefficients
- Determine volumetric drainage areas and drainage radii and recoverable gas for existing wells
- Create filtration model for all of Medina formation
- Forecast increase in total cumulative gas production from infill drilling
- Evaluate hydroslotting treatments and their impact on well drainage area and infill well potential

3. We eliminated more inefficiencies in analysis and design than in the hydroslotting procedure, contrary to what was expected. It was always believed that the greatest inefficiencies of the hydroslotting method would be found in the actual procedure on the basis that it contains the bulk of the expenses. In fact, the time and expense relating to the preparation of the procedure had the most room for improvement and cost reduction. Items include the construction of a mathematical model for each individual well to calculate optimal slot depths, vector dynamics, and chemical reagents for a variety of scenarios within the same formation interval; the development of the appropriate constitutive relationships to relate excavation geometry to permeability enhancement; and the resulting hydroslot design, which is needed to predict spatial permeability distribution as a function of the imposed perforation or slot. Going into the demonstration stage of the project, Hydroslotter Corporation had a strong understanding of stress redistribution, but there were still many unknowns that had to be learned and tested. Some of these unknowns may have been caused by the reticence of the Russian experts to reveal evidence of some education that was considered so basic and necessary that it had to be built from scratch. There were also cultural / hierarchical issues. Work on eliminating inefficiencies in this area continues. That being said, we demonstrated hydroslotting successfully and showed that, practically speaking, hydroslotting works.

4. Hydroslotter encountered and overcame three major procedural engineering impediments. First, hydroslotting a zone in which the hydrostatic pressure exceeds the formation pressure means that the drilling will be overbalanced and this hurts the formation. At the time, the hydroslotting procedure did not call for a lifting mechanism such as foam or nitrogen to lift the water out of the annulus, thereby creating an under-balanced drilling operation. The problem is that under-pressured formations indeed drink water. We now use these lifting mechanisms. Similarly, working fluid cannot be left in the hole overnight because the freshly cut formation will absorb the water and the water will take time to release. Second, the vertical stretch or shrink of the tubing while under pressure was not properly calculated. This could have happened from stretch under high pressure or if the string got "hung up" against the inside of the casing, if the hole was unknowingly deviated. In either case, our assumption that the jet was being properly directed was mathematically calculated but never checked in any of our jobs and generally, we must conclude that we may have been in error. We continue to use the formula, but verify the calculation with a logging procedure that is performed at working pressure. Third, we tested three different configurations. We tested different length slots. We purposely manipulated sand concentrations. We used three sets of perforators (6 nozzles altogether) for the first time. By reducing the number of nozzles to two (one perforator set) from six, the abrasion on the nozzles was accelerated. Our solution was to manufacture better nozzles but also testing of the variable components of the procedure continues.

5. The work performed under this project directly resulted in design and material improvements. One of the greatest achievements of the demonstrations was the understanding gained from working with the intermediate or second-generation tool. Using the guidance of our experience from this project, we were ready to begin designing the brand new "3rd generation" prototype – powerful, standardized, mobile, efficient, and flexible – with the following general goals:

- Durability (stronger metallurgies) for longer service life
- Automated (to some degree) & fewer components for reliability
- Better protection from sand invasion, wear & tear
- Standardized to the industry API standard
- Minimize costs of expensive surface equipment with longer continuous work
- Make better use of the surface equipment, like pumping at maximum pressures

After each demonstration, we were able to take apart the chassis and make deductions. In real time, we saw the technology interact with the surface equipment, such as the rig, pump, sand blender, etc., and how to improve compatibility. By the last demonstration, we understood how to achieve an application cost reduction of more than 50%.

Section C: Results and Discussion

Project Tasks and Work Completed

Task 1: Analysis and Candidate Well Selection

Hydroslotter first started its analysis from a historical point of view and in-depth consulting from Quest Energy. It was discussed that the common method for completing all wells in NY state is with hydraulic fracturing, and secondarily or following up with acidization or acid washes. Hydraulic fracturing is the preferred method because of the underground naturally fractured block system of the Medina formation, highly influenced by natural fractures. Hydraulic fracturing opens up the access to adjoining blocks beyond these natural fractures and creates an increased drainage radius. Very limited production can be created from completions using standard perforation only. Therefore, in known mature and/or stripper wells, hydroslotting was generally expected to create an enhancement in geological formations that would have started as poor producers in the first place.

One of the initial problems encountered was lack of information and inability to collect available information. Generally, NY State reporting requirements are low: most well files do not contain even the most basic of initial information such as wellbore diagrams, core sample analyses, formation tops, gas pressure or other full-value gas dynamic analysis, and filings contain incomplete statements about flow tests or initial shut-in or reservoir pressures. Production information, if available, is often incomplete, missing relevant ongoing wellbore and line pressure information. Further complicating the collection of data was that the current operator purchased many of the wells being reviewed from a purportedly bankrupt previous operator, and neither had filed any permits nor submitted any secondary workover histories on the basis that the state did not require such information. Permits are only required for workover in the different zones of a well, or to change the designation of the producing formation.

Two geological/geophysical reports were written for the project, one public and one private, showing the gas potential of all of the candidate wells and their neighbors in the immediate area. The private report was not submitted due to confidentiality of the subject matter: it identified wells with near-wellbore stress and made recommendations about hydroslotting and geographical locations for in-fill drilling. The public interim report, titled Report on Geological and Field Data Investigation, offered complex analysis, discussion, conclusions, and recommendations regarding the Onondaga, Medina, and Theresa formations.

A significant characteristic of all three formations is that there is a correlation between total gas production of a well and the well's initial reservoir pressure. The maximum gas production of any well is obtained from zones where initial reservoir pressure is the lowest. As discussed in the Report on Geological and Field Data Investigation, the calculated drainage radii of the wells in these formations suggest with a high probability that gas migrates from distant high-pressure areas of the reservoir to low-pressure areas where it is collected and extracted.

In this respect, recommendations for hydroslotting are therefore somewhat positive. By lowering the near-wellbore pressure to a minimum, the effects of the compressive stresses are reversed and drainage is improved. Drainage parameters can practically define the total gas production and are characterized by very low rate of extraction compared to the total in-state gas of the reservoir.

Counter-balancing this positive note is the geological challenge facing the hydroslotting method. In all three formations, the reservoir pressures are significantly lower than hydrostatic pressure. During the hydroslotting procedure, the weight of the column of fluid being circulated back up to the surface will be heavier than the formation can bear and lead to an overbalanced condition. This means that in each workover, significant fluid will be lost into the formation. The result of water invasion is reduced gas productivity as the wells produce water, and it will take time for them to clean themselves up. At the time of the demonstrations, there was no clear answer as to how to deal with the over-balanced nature of the method. Now, in order to create an under-balanced condition in the future, Hydroslotter now adds nitrogen or foam to the circulation to ensure that the formation pressure exceeds the hydrostatic and give the column of fluid the momentum to lift out quickly. In any event solutions were not known at the time and each hydroslotting workover was done in an over-pressured state, which caused production problems.

Task 2: Technology Demonstrations

The strongest recommendation was the expediency of carrying out hydrodynamic testing on the basis that it would assist in developing a program for hydroslotting as well as drilling new in-fill wells. The recommendation was resisted by the operator on the basis of cash flow requirements. Well into the program, the selection of wells was reduced to a narrow band with low potential for increased production. All were in an extremely mature or damaged state and/or ready to be plugged and abandoned. At the same time, these wells offered limited opportunity for Hydroslotter to gain further insight into the expansion or improvement of the technology. Nonetheless, having satisfied the technological requirements of the program, the decision was made to push forward. In the end, this decision was the right one because all workovers produced sufficient gas to be marginally profitable.

The key objectives were not to show the value of re-working an entire well, but to show that hydroslotting could increase production in the different formations. Each demonstration succeeded in showing pressure increases and improved gas production. Equipment costs were inordinate for the purposes of these demonstrations. For financial reasons and issues with the operator, workovers were limited to one day per demonstration. Only in the case of the Theresa well was the workover extended to two days.

1. Our first Medina well demonstration. Drilled in May 1984 to TD 1358', and completed at the interval 1190-1238' ft., with 52 ft of effective pay, this well had the lowest initial reservoir pressure of only 380psi compared to all the other wells in the nearby area. The initial flow was 1057 mcfd, much higher than nearby wells. Cumulative production is 159,628 mcf. After hydroslotting the same zone, daily production increased from <10 mcfd to 35mcfd. However, water production also increased, producing over 450 barrels of working fluid in 2006. In the evaluation period, production declined to less than 15mcfd whenever a column of water would build in the tubing and restrict the flow.

2. The second Medina well demonstration. It is the classic example of a mature stripper well. Drilled in 1983 to TD 1300' and completed at 1192 – 1242', with 31 feet of effective pay, this well had initial flow was 975mcfd and cumulative gas production is 29,183mcf. After hydroslotting the same zone, performance increased 10x from 1.5 mcfd to 15mcfd and flush production was sustained for 3 months. Production continues at 5mcfd, which is a 50% sustained improvement over historical production. In 2006, the well has produced over 100 barrels of working fluid / water production.

3. The third demonstration was the Theresa well demonstration. Drilled in 1996 to a TD of 6174, this well produced 6744 mcf at 5478 – 5496' at an ISIP of 1510 psi from 1996 to 1998 but sat idle until it was hydroslotted in August 2005. Several intervals appeared to be prospective for additional gas within the Theresa formation: (i) 5555 – 5560’, (ii) 5565 – 5572’, (iii) 5608 – 5611’, and (iv) 5623 – 5628’. The second interval was chosen as it was closest to the previous production and near a water layer. We hydroslotted using 3 sets of nozzles but mechanically could not optimize working pressure and shut down the procedure. Production increased to 75 mcfd followed by a rapid decline. The zone was re-slotted and resulted in an IP of 107 mcfd. Reducing the number of nozzles increases the slotting time and accelerates the abrasion on the nozzles. The objective of isolating and/or preventing water problems was successful. In the end, 8ft was slotted, which was sufficient to receive 2135 mcf before the well was shut-in again.

4. The Onondaga well demonstration. Drilled in 1996 to TD 3021’, this well’s inherently low pressure made the Onondaga Formation the toughest of the three NY formations to tackle because of the risk of overbalanced slotting. This gas well could have been damaged by the overbalanced procedure when it went under vacuum would have an adverse impact. Three small intervals totaling 12 feet of by-passed pay were slotted at (i) 1842 – 1848’, (ii) 1852 – 1855’ and (iii) 1865 – 1868’. This Onondaga formation well now produces 11mcfd, over production for the previous 5 years of 2-3 mcfd. The result has evidenced a major water problem, unloading over 3000 bbls in 2005 and over 250 bbls in 2006.

Task 3: Evaluation of Results

In the following year of monitoring, hundreds of barrels of water were produced from the wells on a declining basis. While it is clear that water production was a direct result of hydroslotting (in comparison to years prior to the workover, in which water production was zero), the quantification of gas production increases became more difficult due to operator issues. Results of the demonstration are shown below:

	Cumulative Production (mcfd / mmcf)	**2005**		**2006[1]**		**Total Gas mcf / (% inc.)**
		Gas (IP / mcf)	**Water (bbls)**	**Gas (mcfd / mcf)**	**Water (bbls)**	
Medina1 [2]	<17 / 159.6	35 / ~2700	120	12.5 / ~3700	450	**6400 (+15%)**
Medina2	1.5 / 29.2	15 / 1034	0	5.2 / 1550	120	**2584 (1000%)**
Theresa	0 / 6.744	100 / 1830	0	20 / 305	0	**2135 (+32%)**
Onondaga	12.7 / 87.9	12 / 4336	3150	11 / 3300	250	**7636 (+10%)**

[1] 2006 figures may not correspond with official state figures that have not been released yet.

[2] This figure is not total production, but volume increase attributable to slotting. As negotiated with operator. Total reported mcf vol. = 6193 (2005), ~ 5500 (2006).

Economic Analysis

Marginal quantities of gas increases in this demonstration should not be considered negative, because the absolute numbers relate to the fact that very little gas existed in-place. For example in the Theresa well, the relative increase should be regarded as a positive because hydroslotting increased the commercial life returns by 32% in comparison to conventional completion technologies. It is therefore surmised that if the reserves exist, hydroslotting can reach farthest into the drainage area to make the well a large producer in a way that no other technology can. This leads us to believe that only a fraction of total reservoir is being produced & BCFs of gas are unexplored.

Analysis of the economics of the hydroslotting tool highlights a great obstacle to commercialization. Cost-based models understate the value of the technology. Costs to manufacture the machine are not individually expensive. Tests to date show a relatively long service life for the machines, and this trend in durability is expected to continue as the technology is further improved. Therefore on a rental basis the machine might have a pay-out in a week at $5,000 daily rental charge. The total billing cost of using the machine is more expensive than simple perforation, and less than hydraulic fracturing: these relations have not changed in the last three years. The daily total billing cost of the machine incorporates the cost of the supporting services needed to put it into operation. A third model using the development cost of the machine, because it required highly trained engineers and machinists with a large amount of testing is also ineffective. R&D costs do not continue in the preparation, trouble-shooting, maintenance, and operations on a continuing basis and R&D costs are expected to be recovered with proper marketing.

The increased productivity from using the machine is disconnected from the costs of the hydroslotting machine or services. Depending upon the attributes of the well, productivity increases can have a wide range, from 15% to 200%, as seen in the results of this set of demonstrations. The first Medina well evidenced stabilized production with barely any improvement over the historical production while water was being produced. The second Medina well, on the contrary, showed a massive increase on a sustained basis, with an IP of 1000% the previous production and sustained production of 50% greater.

Based on the market cost of the typical surface equipment to be used in a hydroslotting operation, the total billing cost approximates $10 per foot of depth per application, with a minimum application cost of about $20,000. (There is no price advantage for wells shallower than 2,000 ft.) Thus, for example, surface equipment may cost $50,000 on a 5,000 foot well for one day of work. The productivity of the machine is able to slot 36 feet in a 12 hour day, which allows time for rig-up and rig-down of high-pressure pumping equipment. This amount of slotting is sufficient to cover the majority of effective pay zones in all New York formations.

Pay-outs required to justify hydroslotting in NY are calculated. The cost model assumes the paid-out cost of an operator equals the cost of the operation, plus the added surcharge for royalties (assume 20%) and wellhead expenses, divided by the price of gas (assume US$6.00). The formula below can be used to approximate the cost of a hydroslotting procedure.

$$Q = [\text{ Cost} + \text{Royalty} + \text{Expenses }] / \text{Gas Price}$$

Based on this formula, necessary production for an operator to cover the costs of a hydroslotting workover ranges between 3,500 mcf and 8,000 mcf for deeper formation intervals:

Onondaga cost = $20,000 = 3,500 MCF
Medina cost = $25,000 = 4,400 MCF
Theresa cost = $50,000 = 8,800 MCF

In terms of technological improvement, the Theresa well was the outstanding performer, as the commercial life of the well was increased by 32%. The second Medina well was also an important producer except that the gross volumes of gas and drainage acreage available to the well were low (please refer to <u>Report on Geological and Field Data Investigation</u> for details. The Onondaga well, which was fracced two years earlier, expanded the drainage volume allowed hydroslotting to connect to this increase without creating expanded production. The expanded drainage volume increased reserves from 100mmcf by 50% to 150mmcf. Hydroslotting by-passed pay contributed only to drainage volume, evidenced by an increase in the wellhead pressure, although actual increased production is difficult to verify.

In terms of return on investment, the Onondaga well can be considered to be the most successful, with a payout in approximately 7.8 months. On the other end of the spectrum, the Theresa well did not attain its minimum productivity requirements to become profitable, resulting in fact in a loss of nearly $48,000 according to the formula above. The Medina wells will be able to pay off the workovers in just less than one year, at 11.7 months. This marginal profit is not strong enough for widespread commercialization and forces Hydroslotter to continue research and development with an objective to reduce costs to a preferred pay-out time at less than 6 months.

In terms of comparing hydroslotting to other technologies, the ball remains in the air. More wells require to be completed using this novel technology to show definitive answers. At present, financial comparisons are easier than technological comparisons. The relative economic cost of hydroslotting is more than simple perforation and marginally less than the cost of hydraulic fracturing, and less than the cost of completing a well using simple perforation followed by hydraulic fracturing. Technological comparison would be more easily facilitated if two operations were done side-by-side. On an absolute basis, hydroslotting can be deemed a success as a remedial technology, but has not been used yet as a primary completion technology on a newly drilled well. This is a goal for the future.

Rising or buoyant gas prices are helpful to offset the increasing prices of oilfield service costs, especially rig costs, which rate of increase is astronomical. Due to improvements in the machine and especially in the durability of the nozzles and perforators, hydroslotting cost now has been reduced to the range of $6.00-7.00 per foot of depth. This estimate is based on an in-hole service life of 300 hours and the ability to hydroslot 1,000 feet of formation, as well as the technical supervisor of the machine. These new economics should show that many stripper wells can use hydroslotting economically in today's price environment.

Conclusions and Recommendations

1. Hydroslotting can be commercially viable if several conditions are met. Results of this demonstration effort show that generation of hydroslotter machine used can be economically successful in even the most difficult or marginal of stripper wells. However, it is important to note that from our experience in NY State, first and foremost, hydroslotting is not recommended for use in wells that produced, during their entire commercial lives, less gas than what would be required to pay for a single hydroslotting workover, because the risk-reward balance cannot be justified.

2. While durability is important for the hydroslotter machine, it is a necessity for the nozzles. All aspects of the downhole procedure rely completely on the robustness of the nozzles. Increasing the work load of the operation or the harshness of the downhole environment will require development of a new platform of more durable metallurgies and sub-components. After the demonstrations, Hydroslotter developed a new nozzle made of powerful ceramic carbide metallurgy, and hardened perforators with special alloys with exotic metals. The result of these upgrades has made for faster and deeper cutting (6000 psi and 0.3 lbs/gal). There is an economic saving in that no time is wasted pulling tubing out of the hole every second day and this maximizes the slotting time. The tool now regularly cuts between 15 and 20 feet deep without deterioration. It is clear that the machine can slot 80 hours continuously without deterioration, so money should be saved on surface equipment and pumping pressures can be maximized.

3. It is recommended that new technologies such as hydroslotting be used to enter into the attic gas reserves of the Medina formation. In many cases these reservoirs exceed 25% of the formation. For example, as discussed in <u>Report on Geological and Field Data Investigation</u>, it was shown that the listed analyzed wells had attic gas reserves of 30%, on average, where gas saturation exceeded 30% and porosity exceeded 11%. The upper reserves offer plenty of potential for gas exploitation and hydroslotting demonstration because of the low porosity characteristic. By-passed pay may be plentiful however; if the initial production of the main object of exploitation was low, then the economic collection of gas in the attic reservoir is going to be difficult, and review of offset wells and logs is necessary. All attic reserves are possible candidates with further evaluation.

4. It is recommended that the governmental and regulatory bodies in charge of collection of information set stricter guidelines for reporting requirements. At present, guidelines are grossly inadequate. If an operator wishes to acquire or work over a target well, access to information must be sufficient to determine with clarity whether there is any gas left in-place to pay for a workover. Production history, logs, and formation characteristics should be included in the very basic information that is needed. NYSDEC reporting requirements are currently not strict enough in this regard.

5. Impediments to the development of this technology include the inefficiencies relating to geological / geo-physical qualification process and hydroslot design, and not the actual procedure. Some of the inefficiencies may be attributable to normal growing pains or learning curves of a new technology, while others can be associated with cultural and hierarchical norms. We feel strongly that developing or educating the company with important scientific principles will be the foundation for future generations of the technology and is basic and necessary to improving the design and economics of the hydroslotting procedure.

6. SWC leadership and partnership with industry plays a significant role in encouraging the use of hydroslotting for stripper wells. The SWC has given Hydroslotter the platform needed to market the hydroslotting technology. Industry's current R&D goals and (political) perception of future R&D requirements do not focus on technological operations in stripper wells and there was no other similar platform that could be used for the development of hydroslotting at a critical time in its growth... It is important that industry and the SWC collaborate to encourage the development and use of new technologies like hydroslotting to prepare for the future.

7. A critical leadership role for the SWC is to convince the industry and society at large that future gas reserves will be produced from stripper well reservoirs. The SWC's prediction of future requirements to extract gas from stripper wells is correct. The US oil and gas industry must have the means to exploit reserves to meet the nation's current and future demand. This will in turn have a significant impact on the US economy. In addition, the SWC's focus on new technologies helps reduce the risk and offset chances for loss. On a broader note, the political vision of the government does not strictly agree with the vision of the SWC that the development of new oil & gas technologies will be an important factor in maintaining energy reserves in the future. It is vital that SWC maintain and that the industry support and strengthen the SWC's leadership role to improve the production performance of the nation's natural gas and oil stripper wells.

References

The principal author and editor of the Report on Geological and Field Data Investigation, was Dr. L. Marmorshteyn, Technical Director, Hydroslotter Corporation, in collaboration with Dr. V. Neiman and Dr. J. Basin.

Appendix A: Scientific Principles of Hydroslotting

1. Introduction

There has been abundant research in USA and abroad that shows that the physical state of the area immediately around a wellbore (near-wellbore zone or NWZ) in a fluid-producing interval or zone significantly affects the well inflow during the process of drilling and exploitation of oil and gas reservoirs. Therefore, stress concentration in the NWZ by definition also exerts critical influence. NWZ stress is almost always caused in the drilling process, but NWZ stress is most evident in older or mature wells, because the NWZ has undergone years of slow damage. Research has found that in vertical wellbores, increased tangential stresses in the NWZ negatively affect the physical characteristics of the formation rock. In particular, there is a considerable decrease in the permeability of the productive layers. (It is understood that directional or horizontal wellbores will also sustain NWZ damage, but this has yet to be demonstrated or quantified through publicly available research.) Further, Hydroslotter and other investigators have shown through laboratory simulations of true physical conditions, this correlation between formation permeability and pressure exerted upon it.

As a result, the method used by Hydroslotter, under which the pressure in the NWZ is essentially decreased, reverses this dependence, creating an artificial condition in the NWZ where formation pressure is reduced below what is found in the pre-drilling natural state, arousing a multi-fold increase in NWZ permeability in the collector. This report describes the hydroslotting method, the results of industrial hydroslotting demonstrations in New York State, and discusses further steps in discharging pressure in the NWZ, overcoming mud invasion in newly drilled wellbores, and further increasing the area of filtration, the drainage radius, and the use of hydroslotting in conjunction with other completion methods.

1. The Near-Wellbore Zone

A hydrocarbon-producing rock formation begins a process of alteration after the stratum is opened by a drill hole. As the rock adjusts to the presence of the wellbore, there is a transformation of the properties in the collector immediately around the wellbore. The part of a collector adjusted to the well, where the quality of reservoir has been changed, is called the near-wellbore zone ("NWZ"). The most important practical impact of this process is the reduction of permeability of the collector in the NWZ.

The NWZ appears in various forms, especially in fractured and fractural-porous reservoirs, but in practice, it is accepted as cylindrical in shape and is characterized by a relatively uniform radius and height. For hydrodynamic calculations, in the absence of core samples and other physical materials with which to test under laboratory conditions, the actual properties of the zone cannot be used. Instead, for the simplification of hydrodynamic calculations, the formation rock inside the NWZ is mathematically considered to be homogeneous and isotropic. Therefore, the hydrodynamic effects are estimated as if the rock was homogeneous, and this causes calculations to differ seriously from the real characteristics of the rock formation in the NWZ due to the actual heterogeneity, fluid movement, and non-isotropic stress.

The sizes and parameters of the NWZ change constantly throughout all the periods of a well's existence, from the state prior to drilling, to the drilling of adjacent wells, to the eventual plugging and abandonment. The diameter of the NWZ ranges from less than a meter (approx. three feet) to rarely exceeding a few meters, in porous formations. The condition of the NWZ defines the hydraulic relationship between the well and the reservoir; despite its small size, it is the largest single influence on well productivity. A large decrease in permeability in this zone during drilling or long-term preservation of the well could lead to complete isolation of the well from the reservoir.

There is general agreement that wells drilled a longer time ago contain NWZ with greater damage and size than in those wells drilled recently. Advancements in the oil and gas E&P industry have led to better drilling methods to reduce compression of the rock in the NWZ, better drilling muds to reduce chemical and physical effects on the reservoir, and better perforation, fracturing, and other well completion techniques to reduce plugging of porous channels by fines and emulsions.

There are a number of stimulation methods used for the remediation, recovery and/or increase of the natural permeability in NWZ. The main methods of recovery or remediation include open flow drainage, pumping of surface-active materials and thermal influence. The most widely used methods to increase permeability include acid treatment and hydraulic fracturing.

Open flow drainage is the most widely applied method of well completion, providing good results during well completion, especially in highly permeable collectors or those with relatively low penetration of drilling mud. In low permeability collectors, open flow drainage cannot provide such positive effects on its own and other methods need to be used.

Surface-active materials applied to the NWZ can eliminate emulsions, reduce clay-type minerals swelling, and destroy fines or asphaltenes in the filtration channels and phase boundaries (gas/oil/water), all of which promote a renewal of natural permeability. Generally, surface-active materials are used jointly with other methods since their effectiveness on their own is not high enough.

Thermal methods are increasingly used in heavy oil collectors to reduce oil viscosity and clear the filtration channels of paraffin or other resinous substances.

Acid treatment is widely used and is highly effective. The main disadvantage of acid treatment is economic and related to the necessity of hydraulic connection between the well and reservoir, as well as the fact that there is no single treatment for all collectors, especially in the case of heterogeneous reservoirs. Besides this, when acid treatments fail, the ensuing decrease in collector permeability is often irreversible. In numerous cases, this is just a result of incomplete removal of the reaction products, especially in terrigeneous collectors.

Hydraulic fracturing creates bottom-hole zone fractures by injecting liquids at high pressure. Of all the methods, it is the most technical and complex. Special proppant material, such as frac sand, is added to liquid or gels, in order to fix open the apertures of the cracks. This is the most effective method of increasing well productivity because the depth of influence extends up to tens or even a few hundred meters. However, the main deficiency of this method, of course, is the absence of control, direction, and manipulation of the fracture(s). For example, a fracture will propagate in the most permeable rock of a heterogeneous collector; orientation of the fracture is defined by the natural complex stress-strain condition of the rock and orientation of natural fracturing; often the direction and extent of a fracture cannot be predicted, especially in newer, softer deposits. The uncontrollability of the hydraulic fracturing process can lead to the unwanted spreading of cracks to water-saturated collectors.

None of the present methods listed above eliminate the original reason for the decrease in collector permeability – stress concentration around the near-wellbore zone.

2. The Relationship of Formation Pressure and Permeability.

The critical role of pressure on permeability. The major sources of natural formation pressure are overburden, tangential, and lateral (pressure from all sides). The deeper the formation, the greater is the pressure. In a well, or more specifically the near-wellbore zone ("NWZ"), the pressure that requires being relieved is the difference of the overburden and hydrostatic pressures. For example, at a depth of 1000m (3300ft.), the pressure to be relieved might be 250atm – 100atm = 150atm (3700psi – 1500psi = 2200psi), to achieve proper unloading of the stress in the NWZ. Bearing in mind that the density of rock increases by 1% and porosity decreases by 1% for every 100m (330ft.) of depth; permeability declines at a much higher rate, approximately 10-20% per 100m (330ft). For example, if permeability at 1000m is 1 Darcy, then at 1500m (5000ft.), it will be one-third to one-half less, yet the hydrostatic pressure will only have increased by 50atm (750psi). Therefore, in a lower zone of the same productive layer, but 500m (1700ft.) deeper, the well productivity will be proportionally less due to this decrease in permeability.

An illustration of the critical role pressure plays on inflows of fluids is shown by the fact that the different geometry introduced into the formation by drilling, doubles the pressure on the wellbore. In our example, if the efficient formation pressure at 1000m (3300ft) is 150atm (2200psi), the pressure on the wellbore walls will be over 300atm (4400psi). This is identical to a pressure increase that would be expected if the formation depth was tripled, i.e. if the well was deepened from 1000m (3300ft.) to 3000m (9900ft.). There is a proportional drop in porosity, and likewise a drop in inflow of fluids. Conversely, if a method could remove or reverse this pressure, it would be identical to a pressure decrease that would be expected if the well was half as deep, from 1000m (3300ft.) to 500m (1700ft.).

The stress dependence of permeability is well established for hydrostatic stress state in laboratory experiments under confining pressure. Compilation of some published data on a variety of rock types (Gray and Fatt, 1963; Marmorshteyn, 1975; Yale, 1984; Walls et al, 1982; Morrow and Byerlee, 1988) clearly demonstrates that rock matrix permeability decreases with increasing pressure and the magnitude of this reduction is related to initial, low pressure permeability values. Permeability reduction curves basically cluster rock types into two major groups (1) granular reservoir rocks with higher porosity and initial permeability; and 2) low porosity/low permeability rocks with micro-crack related permeability. The decrease in permeability caused by stress is much greater in the latter rock type and can reach reduction 70 to 90% reduction at a very moderate mean stress of 100-150atm (1500-2200psi).

State of pressure around the wellbore. The drilling of a wellbore alters the pressure regime in the NWZ from an isotropic state to anisotropic compression. The wellbore, the dominant factor in determining near-wellbore stress, exerts considerable negative influence on permeability. The greater the distance from the wellbore, the less will be the influence of the compressive and radial stresses caused by the wellbore on the formation; at some distance the stresses caused by the wellbore will equal the stress condition of the rock in its natural state, which can be approximated as hydrostatic pressure. The deeper the well, the farther out from the wellbore will the zone exert its influence to its derivative limit; the stress regimes in the zone of influence will dilate proportionally. Additionally, in all types of rock, the greater the natural hydrostatic pressure, the less is the natural permeability and the possibility of inflow of fluids.

To calculate stress around a cylindrical hole at a certain depth $\boldsymbol{z}$ one needs to know the overburden pressure $\boldsymbol{P_z = \mu g z}$, where $\boldsymbol{\mu}$ is the bulk rock density, $\boldsymbol{g}$ is 9.8 m/s^2. There are also two principal horizontal stresses $\boldsymbol{P_x}$ (lateral pressure) and $\boldsymbol{P_y}$ (tangential pressure), whereby $\boldsymbol{P_1 = P_x + P_y + P_z}$. For deep wells in sedimentary basins characterized by extensional paleotectonic regime the stress state can be qualitatively approximated as $P_z > P_x = P_y$ where P_x and P_y are approximately identical values. The horizontal (uniaxial) stress condition for P_1 results in a formula that can be described as:

$$P_1 = P_z\,[v / (1-v)] = \lambda P_z$$

Where λ is the Poisson coefficient of a rock at the depth of interest, which is the ratio between the transverse and longitudinal stresses in a solid body.[3] Assuming as a first approximation that a formation is subject to isotropic stresses, P_1 would be the total stress state around a cylindrical hole filled with fluid. Bear in mind that this math is inaccurate because of the improper assumptions about isotropy.

Removal of pressure from around the wellbore. The objective of Hydroslotter Corp. is to calculate the force required to unload the wellbore-related stress in the NWZ. For this, it is necessary to know the elastic modulus of the rock because, for practical purposes, Hydroslotter's industrial method to eliminate the uniaxial compressive stresses of the rock inside the NWZ (i.e. those impacted by drilling and operation of a well) will have a different effect on the same rock beyond the NWZ.

In an example of removal of pressure in nature, formation pressure will be (partially) discharged in an area bordering a cavernous space, because the proximal elastic-plastic rock gradually fills it in and undergoes a process of relaxation; however the distal rock does not transform. In the case of a wellbore, the formation exposed to the borehole can partially discharge while the borehole is open, but much of the drilling-related compaction pressure becomes restored beyond the wellbore wall just after the casing has been cemented in place. Therefore, any permanent cavity, natural or man-made, with sufficient depth and thickness, can be used to remove stresses in the NWZ completely that will not be restored later.

It should be noted that accuracy in determining the elastic modulus of a rock is the result of a somewhat subjective evaluation by the practitioner testing the rock behavior. Results of the different methods used to calculate the elastic modulus tend to vary slightly. While this technical discussion is not

[3] It should be noted that Western geophysical academia commonly accepts that the Poisson coefficient may only have values ranging from 0.0 to +0.5. In the more complex Eastern European interpretation, it has been shown through thermodynamic analysis of several rock types that no law of geophysics forbids a negative value of λ, and that λ may in principle have values between –1.0 and +1.0.

directly important to the subject of the report, the general conclusion that requires transfer is that the compaction in the entire depth of the NWZ must be neutralized, or if possible reversed, for the hydroslotting effect to be optimized.

The depth and thickness of such a cavity can be calculated. In general, it can be said that the zone of influence of the NWZ in elastic rock types extends outwards about two to three wellbore radii from the wellbore. In elastic-plastic rocks, the zone of influence extends deeper into the formation, but the maximum stress level does not abut against the wellbore. The maximum size and magnitude of a man-made cavity that exceeds the size and magnitude of the NWZ, i.e. at the limit of collapse, can be predicted using the Basin ratio, $\boldsymbol{\vartheta}$, which becomes a critical parameter in designing hydroslot structures in wells with abnormal formation conditions, such as those that are high-pressured, mobilized, or unconsolidated.

Stress state around the hole with symmetrical longitudinal slots. The hydroslotting method designs two fairly deep, artificial cuts parallel to the well axis across the whole thickness of the potential pay zone. The effectiveness of this novel well completion technique is expected to be especially high in low porosity/permeability gas reservoirs wherein the production rates are strongly influenced by fracture permeability and formation damage. The theory is that the symmetric cuts relieve the radial stress around the hole, bypass the formation damage zone, increase the drainage surface, and, as a consequence of all these effects, significantly increase reservoir permeability. In what follows, we will discuss the physical basis for this technique, geological prerequisites of its most effective utilization, and some representative field results.

The schematic drawing of the situation is shown in Figure 1. Given a sufficient aperture ***2t*** of the slots, the hole with the two symmetric slots can be approximated by a straight cut with dimensions in the vertical plane ***2a*** by ***2b.***

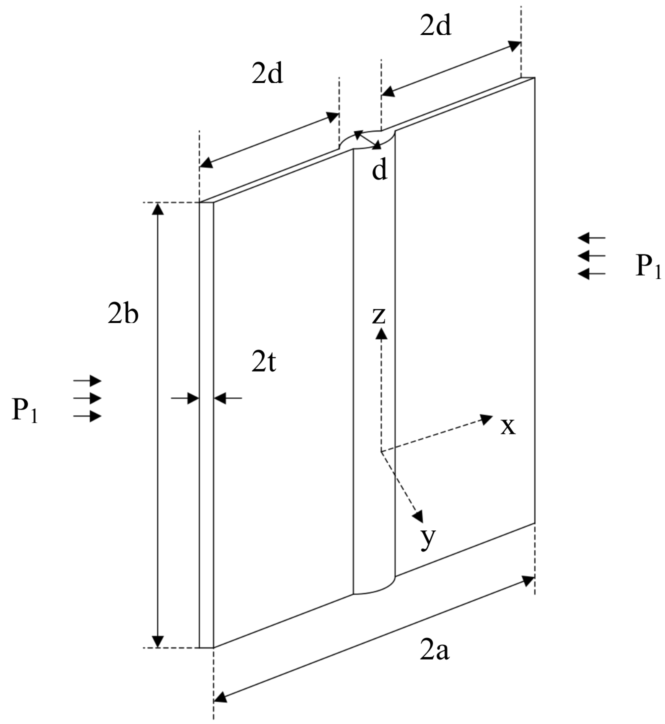
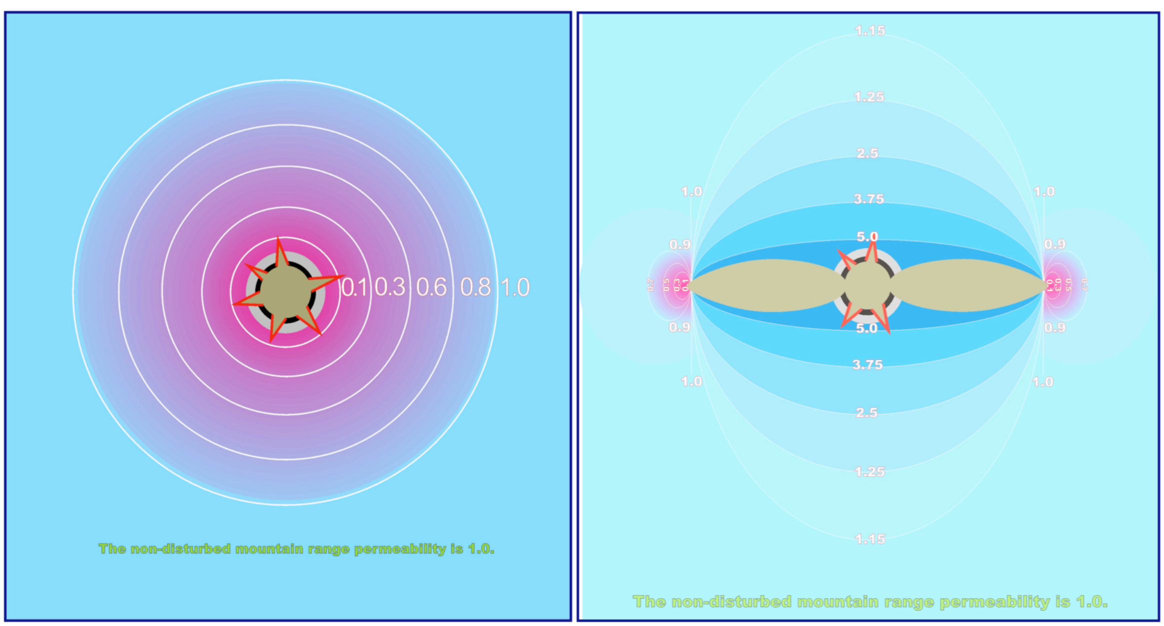


Figure 1: the stress state around a wellbore with longitudinal cuts.



Figures 2(a) and 2(b) demonstrate the transfer of near-wellbore stress (in red) away from the near-wellbore zone out to the distant tips of the hydroslotter slots. Note that near-wellbore permeability from hydroslotting has increased to 5.0 times the original in situ permeability potential of the zone of interest of 1.0, compared to a decrease in permeability to 0.1 from standard perforation.

If $2b/2a >= 2$, the stress calculation around the cut is reduced to a plane strain problem solved by Muskhelishvili (1953):

$$P_y = P_v - P_f\left[1 - \frac{(y^2-1)^3(y^2+1)}{(y^4-2y^2\cos 2\theta+1)^2}\right]$$

$$P_x = P_v - (P_v - P_f)\left[1 - \frac{(y^4-1)(1+2y^2+y^4-4y^2\cos 2\theta)}{(y^4-2y^2\cos 2\theta+1)^2}\right]$$

$$P_z = \frac{(P_x+P_y)}{2}$$

Where the Cartesian coordinates x, y, and z are oriented with respect to the cut as shown in Figure 1. The slot, unlike a circular hole, results in a significant stress relief of the productive bed in the y-direction, i.e. perpendicular to the cut. This is shown in Figure 2(b). Note that (i) all three stress components are subject to reduction, (ii) the most dramatic effect is achieved for the P_x stress component (2.5 fold reduction on the wellbore wall) and (iii) the stress relief zone extends deep into the productive bed (up to 10 borehole radii). The minimal aperture $2t$ of the slot that would prevent the tips of the hydroslot from closure for an elastic, isotropic bed in an isotropic field is given by (Nordgren, 1972):

$$2t = \frac{2a(P_z - P_l)(1-v^2)}{E}$$

For example, a slot with x-axis dimensions of $2a = 1$ meter, at a depth of 3000m, where $v = 0.25$ is the Poisson co-efficient and $E = 5GPa$ is the Young modulus of the formation zone, one obtains $2t = 18mm$. It is noteworthy that while the minimum aperture required to enhance stress relief is $2t$, for practical purposes, the ratio of the aperture to the wellbore diameter exceeds 15 times, $d/t >= 15$. By increasing the depth of the zone of interest to 7000m, the required dimensions become $a = 50cm$, $b = 1m$, and $t = 36mm$. The maximum concentration of stresses decrease between 20 and 40 times. There is no need for a subsequent hydraulic fracture to induce greater near-wellbore permeability.

Effect of the stress state on reservoir permeability. Interesting that, unlike the cylindrical hole, the artificial cut leads to a pronounced reduction in the vertical stress which is beneficial in terms of including bedding-parallel micro-fissure permeability.

By making use of the stress distribution around the hole before and after cutting, one can map the permeability as a function of distance away from the wellbore wall. For practical purposes of estimating the effect of hydroslotting on the predicted rate of hydrocarbon production, it is probably sufficient to visualize that the wellbore radius has expanded by several radii into the near-wellbore zone, where the permeability around the hydroslot interval of the wellbore will be greater than that in the undisturbed reservoir. The radius of this zone will be greater than the radius of effective permeability reduction due to the former tangential stress around the cylindrical hole.

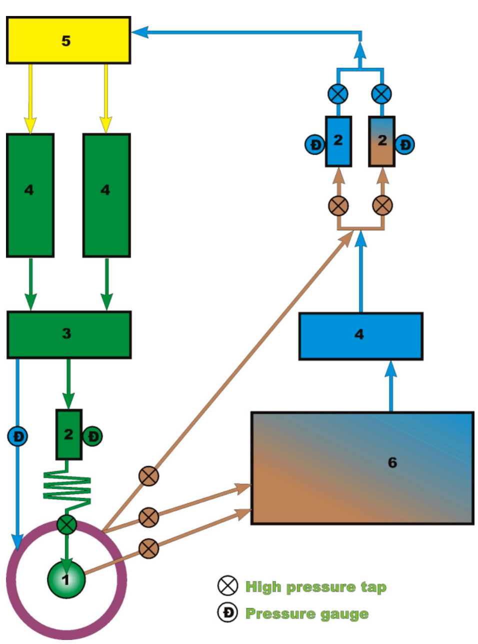
Appendix B: Typical Hydroslotting Procedure

The objective of the procedure is to clean out the well to below the pay zone; log well and correlate production zones; slot selected intervals; and return the well to production. Safety is the first priority in the operation and maintenance of the hydroslotter.

Surface Equipment Checklist

Hydroslotter plus accessories	Casing scraper – OD fits casing ID
Workover Rig w/ shaker pit	Pup joints – two each of 2 ft., 4 ft., 6 ft.
Tanks to hold 2 wellbore volumes	Logging unit (Gamma / CCL service)
High Pressure Pumping Unit(s) (5,000 psi)	Pressure gauges and Valves – 2 each
Sand Blender w/ filters	Completion fluid
Blow-Out Preventer (B.O.P.)	Quartz Sand 20/40 mesh
Tubing to depth of well (pressure 6,000+ psi	Gauge Ring
Additional tubing – 10 joints	

LAYOUT OF SURFACE EQUIPMENT



1. Wellhead
2. Pulp-cleaning filter.
3. Manifold unit.
4. Pump set.
5. Sand-mixing set.
6. Tank.

Step-by-Step Procedure Checklist

1. MIRU workover or service rig. Spot rig, pump & miscellaneous equipment.
2. POOH with old tubing and packer. If applicable clean out cement retainers, bridge plugs, etc. with power swivel, drill collars and metal muncher mill. Circulate junk to top and remove.
3. RU surface equipment to enable circulation of completion fluids and slurry. Reverse flow connections are helpful but not necessary, i.e. forward and reverse circulation. All surface equipment is connected with the block manifold configured to allow formation sludge to be removed during the hydroslotting operation. Filters installed throughout connections to enable changing mid-process without stopping circulation.

NOTE: Ensure wellhead fitted properly with standard blow-out prevention equipment (B.O.P.).

4. Tally & drift in hole with gauge ring on end of tubing to PBTD. Pull up off bottom.
5. Circulate hole with clean working fluid. Circulate bottoms up or until free of all debris in #1 (if applicable). POOH.
6. Tally & PU fully assembled hydroslotter machine DHA. Select positioning of hydroslotting DHA (to be determined and coordinated by HSC) to lowest zone to be slotted.
7. RIH with Hydroslotter DHA on end of 1 jt. Tubing, 2 x 2' pup joints, and remaining tubing.
8. Circulate well at low pressure to re-check that wellbore is clean.
9. RU high-pressure surface equipment in accordance with HSC recommended design, including pump, blender, and recorder unit. Manifold in tanks, lay hard line to tubing. All equipment is to be reviewed by HSC on location.
10. Hold safety meeting with all personnel. Review job and all safety issues. Review parameters.
11. Pressure test tubing to 5000 psi for leaks using Hydroslotter test sub in DHA. Pressure down. If test good continue; if not, replace failed joints.
12. RU wireline unit with Neutron / gamma ray / collar locator logging tool. RIH & log with locator tool in target interval(s) & pay zone(s). Use centrator to orient direction of tool.
13. Pressure up tubing and correlate log again to 2 x 2' pup jts. Use centrator to orient direction of tool. Calculate & verify tubing stretch / shrink.
14. RD wireline loggers.

15. Correct placement and direction of hydroslotter DHA across selected first target interval at bottom of pay zone according to logs & centrator.
16. Close safety valve and pressure hard line.
17. Wash well and test pressure, flow for different scenarios and test surface equipment with 6,000 psi. Follow pump operator's recommendations for pumping procedures. Lay return line from backside to return to pits.
18. Forward circulate working fluid 1x tubing volume. Drop hydroslotter working ball to seal off opening in bottom of hydroslotter and allow ball to seat. Set pressure to 1.3 times the pre-calculated working pressure ($\triangle$P).

NOTE: Operation should do mechanically what was calculated mathematically in pretreatment analysis, which is to optimize working pressure $\triangle P$. If $\triangle P$ is approximated but not optimized, it is strongly recommended that the hydroslotting operation be re-calculated before proceeding. If recalculated procedure is not attainable, POOH, reconfigure hydroslotter, start again.

19. Slowly raise circulation to $\triangle$P. If any unexpected, abnormal, or unexplainable pumping operation occurs, i.e. poor or no circulation, stop operation. POOH, fix problem, RIH again.
20. Function test hydroslotter for five (5) minutes with working fluid at rate of 1 barrel / minute (bpm) for friction check. Increase pump pressure to 5,000 psi and monitor. Pump until satisfied with hydroslotter tool performance.
21. Proceed to mix sand and begin slotting of first selected interval. Measure sand concentration constantly for first ten minutes until concentration has stabilized. Monitor sand concentration and filters to maintain appropriate sand concentration level.
22. Job to slot from bottom to top of interval. Estimated time is 50 – 60 minutes for each slot.

NOTE: During slotting, HSC engineers will control rate or any other changes to system.

23. Pull up to next slotting position at end of first slot. When hydroslotter is ready to be moved to next interval, circulation should be started again with necessary $\triangle$P. Hydroslotter machine remains in well until nozzles are destroyed or until necessary $\triangle$P can no longer be attained.

NOTE: TO PREVENT GETTING STUCK, TIME TO REPOSITION HYDROSLOTTER IN BETWEEN SLOTS MUST NOT EXCEED FOUR MINUTES. IF REPOSITIONING EXCEEDS FOUR MINUTES, WORKING FLUID SHOULD BE CIRCULATED AND CLEANED OF ALL SAND BEFORE OPERATION RECOMMENCES ON NEXT SECTION.

24. If necessary $\triangle$P can no longer be attained, POOH. Remove old nozzles and return to step 9. When replacing nozzles, visually check integrity of hydroslotter machine.

25. After slotting, is completed, reverse circulate clean working fluid through hydroslotter machine 2 wellbore volumes or until no sand appears in fluid returns. Watch for working ball to come to surface.

26. Re-position hydroslotter tool at initial slotted intervals. Pump chemical reagents to slotted formation as follows:

   i. Pump chemical in tubing
   ii. Pump working fluid
   iii. Close casing head valve
   iv. Pump working fluid
   v. Wait 0.5 hour stop
   vi. Bleed off pressure
   vii. Open casing and tubing head valve
   viii. Circulate well minimum 2 annular volumes of working fluid.

Move up hydroslotter DHA and treat each slotted zone.

27. RD & release pumper / blender.

28. POOH with work string and hydroslotter DHA. LD hydroslotter DHA.

29. RIH with packer & (other production DHA if required). Set & test packer.

30. Nipple down BOP and nipple up production tree / pumping head assembly.

31. RU swab unit to swab well. Swab well until flow starts on its own. Solids from slotting process must be removed to prevent damage to rod pump in the case of an oil well.

32. Return well to production and monitor.

33. Disassemble hydroslotter according to standard procedure. Wash and dry hydroslotter. Clean all working surfaces with diesel. Polish if necessary. Cover all parts with lubricant to prevent rust. Check and change if necessary all screws, nozzles, and other worn parts. All interior parts must be free of scratches, corrosion, or dents. Note any threads or parts damaged or broken for repair & replacement. Package hydroslotter and prepare for transportation.

34. Mission complete!

Demonstration of Hydroslotter Technology on New York Stripper Wells: Report on Geological and Field Data Investigation

The main task of the geological and field data investigation was to estimate the possibilities and methods for gas recovery for Hydroslotter Corporation's project with the Stripper Well Consortium. In upstate New York, we investigated production wells that are located in two main areas: Genesee County (60 wells) and Chautauqua County (15 wells), where the main production object is the Medina formation, which consists of Early Silurian sandstones; and we investigated all Chautauqua deeper wells for access to the Theresa formation, discussed in its own report. Although this report is based on the results of our analysis of log data and field-geological observations that were received in the process of drilling and exploitation of gas wells in Genesee County and Chautauqua County (mainly), it also represents Erie and Wyoming Counties (practically). Data analysis was difficult due to the blatant absence of minimum necessary initial information that is collected under New York State regulations; for instance, missing well bore diagrams, core sample analyses, full value gas-dynamical analyses, and regular measurements of bottom-hole and reservoir pressures, etc.

Initial Data:

- Geo-physical Investigation System ("GIS") Log Results of 43 production wells
- Annual gas production for 60 production wells in the period from 1985 to 2003.
- The initial reservoir pressure of 18 wells for 1984.
- The initial production (gas flow) of 21 wells and bottom-hole pressure of 14 wells.
- A geographical map showing the locations of the wells
- Another 100 wells are located in the immediate area, but well data was absent.

Work Procedure:

- Reviewed and analyzed the initial data, especially the log information to estimate gas saturation intervals and their "filtration-capacitor" characteristics.
- Determined the following characteristics about the Medina formation in the area and for each of the 43 individual wells: the effective thicknesses of gas saturation (H_N) and filtration thicknesses (H_F), porosity coefficient (*m*) and gas saturation coefficient (S_G).
- Determined possible volumetric gas drainage (Vdr) for 57 production wells.
- Determined min./ near-max. drainage radius (Rdr) (for wells where linear gas reserves exist).
- Created filtration reservoir model from complex analysis of gas exploitation and log data.

Summary of Conclusions and Results:

- Determined that total well production is sourced from less than 50% of the entire reservoir.
- Displayed methods to increase gas production from the Medina formation by:
  - Primary completion of existing pay zones using hydrojet slotting
  - Secondary completion by hydraulic fracturing in poor drainage zones even after slotting
  - Selective exploitation of the top part of the Medina that is currently not the choice for gas production (by-passed), which contains, on average, 30% of all Medina gas resources, with maximum and minimum ranges from 10 to 70%
  - Drilling additional wells drilling in the most prospective zones minimally or not impacted by the drainage of gas from nearby production wells.

1. Characteristics and Properties of the Gas Reservoir.

The object of gas production is Early Silurian sandstone of the Medina group. Structurally, the Medina object is confined to a monotonous monocline that slopes downward from the north to the south. The deepest absolute altitude of the lower face of this gas productive layer is in the well Foss 1 (652 ft.) and the highest is in the well George 2 (217 ft.). Therefore, the gas column is 400 ft., if one supposes that those wells are related to the same reservoir. We note, that water saturated sediments in the well Foss 1 are not evolved. The total average thickness of the Medina formation is 100 ft., with variations from 70 to 150 ft. along the area.

The main exploitation object is the massive sandstone at the bottom of the group ("Object I"). The thickness of Object I varies from 35 to 85 ft. in different zones, with an average thickness of approximately 50 ft. The shale layer in this object is insignificant. In the upper part of the formation, above Object 1, there is another gas-saturated sandstone with less significance. This part contains, on average, 30% of the in-state gas that is available from the total thickness of the Medina group, with variations between 3-60%. This part of the section was not flow-tested. GIS logs and geological-field well data were used for characteristics of production sediments. As follows from the log data analysis, the porosity of the gas-saturated sandstones varied from 2 to 11% and gas saturation from 20 to 75%. Variation of rock characteristics of parameters m and S_G are shown (Figures 1 and 2). For more than 80% of the gas-saturated part of the section, the value m varies in the interval 4-8% and on average is equal to 5.5% for 770 ft. of section. In this section approximately 65% of gas saturated rocks has a value S_G of 40-75%, thus the most part of the gas-saturated rocks has value of S_G that is inherent to sediments with waterless gas flow. However, approximately 35% of gas-saturated rocks has a gas-saturation of less than 40%. From practice, it is well known that for this value of S_G from the well we can obtain water, water and gas, or neither. Water flow for the 20-year period is not registered. Because of the absence of flow test data for each interval, a criterion was developed for maximum possible gas saturated thickness, H_N, in other words the layer's ability to produce gas for the existing exploitation system, and also a criterion for filtration gas in gas-saturated thicknesses, H_F. The gas filtration thickness is the layer's thickness where the process of gas filtration can be described according to Darcy's Law.

<u>First criterion.</u> From analysis of data m and S_G, it appears that these two parameters clearly show a correlation for layers where S_G is more than 33-35% (depending on porosity) and separated layers for Objects I and II. On Figures I and II, we compare the values W_G ($W_G = m*S_G$) and m, which also accounts for the correlation above. On Figure I, these parameters are compared for Object I, and on Figure II, for Object I. All points near Line I include rocks with maximum gas saturation; Lines II and III are the average correlation lines for Objects I and II; and all points below Line IV includes rocks with minimum gas saturation, where there is no connection between m and S_G. In general, this analysis shows that the rocks in Object I and Object II can be characterized as low porosity granular, mostly hydrophilic, sandstones, with middle and fine grain sizes.

From experience, it can be assumed that water and gas flow mobility in this type of rock, below Line IV, are characterized by very low, practically nil phase permeability for gas and water. It is possible that the gas in this rock is in a dispersed phase condition and has no connection to the water. From this rock, gas can still be partially extracted even after reservoir pressure has been significantly reduced. The main feature of these gas-saturated sandstones is that gas saturation strongly depends on the elevation level in the section, but also on the characteristics of the producing layer. We can see that the upper object is mostly unsaturated, and this is registered in Object I in the well Kazmak 1. On the contrary, for well Buckenmeyer 2, the sandstone for Objects I and II is characterized as fully gas-saturated. It is possible that this feature of saturation has to do with the fact that the water and gas are not completely segregated in the reservoir. The maximum value of effective thickness, H_N, is the sum of all rock thicknesses where S_G > 33% (see Table 1). In the future, it would be expedient to check this criterion experimentally, to elaborate all active gas resources and more accurately estimate the exploitation system.

Table 1. The main parameters for total and filtration gas reserves for Objects I and II.

Well Name	Object	Depth, ft.	Altitude, ft.	H_N (ft)	Lg (ft)	Lgf (ft)	W_G	W_G f
DLSP 2	I	1329-1379	399-449	44	1.40	1.30	0.0279	0.0255
	II	1271-1321		15	0.40	-	0.0080	-
DLSP 3	I	1330-1372		42	1.38	-	0.0330	-
DLSP 4	I	1408-1457	433-482	41	1.29	-	0.0276	
	II	1350-1399		14	0.31	-	0.0064	
DLSP 5	I	1362-1406		39	1.36	-	0.0310	
	II	1306-1360		25	0.62	-	0.0115	
DLSP 6	I	1342-1400	412-470	49	1.62	-	0.0271	
	II	1300-1340		12	N.D.			
DLSP 7	I	1402-1454	442-494	50	1.6	-	0.0307	
	II	1353-1400		10	N.D.			
DLSP 8	I	1406-1448	456-498	42	1.39	-	0.0333	
	II	1370-1404		10	N.D			
DLSP 9	I	1366-1416	411-461	48	1.60	-	0.0320	
	II	1310-1354		10	N.D			
DLSP 10	I	1352-1400	442-470	32	0.89	0.59	0.0186	0.0122
	II	1314-1350		10	0.33	-	0.0091	
DLSP 11	I	1319-1370	389-440	42	1.22	-	0.0240	
	II	1258-1311		24	0.60	-	0.0114	
DLSP 13	I	1320-1370	405-455	47	1.68	1.64	0.0337	0.328
	II	1262-1318		19	0.58	-	0.0104	
DLSP 14	I	1280-1344	310-434	56	1.86	-	0.0291	
	II	1230-1272		9	N.D			
DLSP 15	I	1284-1335	364-415	49	1.79	-	0.0351	
	II	1228-1280		28	1.73	-	0.0140	
DLSP 16	I	1342-1384	404-448	39	1.28	-	0.0308	
	II	1300-1336		14	N.D			
DLSP 17	I	1364-1414	414-464	50	1.65	-	0.0330	
	II	1310-1360		6	N.D			
DLSP 18	I	1378-1420	428-470	37	1.02	-	0.0238	
DLSP 19	I	1338-1382	386-432	28	0.92	-	0.0210	
	II	1310-1320		5	0.012	-	0.0012	
DLSP 20	I	1366-1410	406-450	37	1.15	-	0.0261	
	II	1327-1362		11	0.34	-	0.0097	
DLFC 1	I	1189-1243	319-373	38	0.92	0.8	0.0170-0.0157	
	II	1131-1177		6	0.56	-	0.0023	
DLFC 2	I	1198-1256	343-401	36	1.39	-	0.0239	
	II	1142-1192		22	N.D			

DLFC 3	I	1186-1244	324-382	52	1.28	1.06	0.0197	0.0162
	II	1143-1181		14	0.31	-	0.0082	
DLFC 4	I	1188-1271	298-381	78	2.18	-	0.0263	
	II	1156-1176		14	0.40	-	0.0020	
DLFC 5	I	1238-1274	358-404	40	1.11	0.92	0.0241	0.0201
	II	1180-1220		10	0.18	-	0.0046	
Os 3	I	1540-1589	500-549	42	1.18	0.82	0.0242	0.0167
	II	1488-1528		14	0.31	-	0.0077	
Buck 2	I	1498-1542	481-530	38	1.27	1.39	0.0189	0.0316
	II	1460-1496		16	0.71	-	0.0196	
Kub 2	I	1434-1467		33	1.08	0.74	0.0270	0.0185
	II	1374-1430		10	0.28	-	0.0050	
Kurn 1	I	1568-1616	508-566	42	1.48	1.33	0.0308	0.0277
	II	1530-1560		14	0.34	-	0.0113	
BNT 1	I	1443-1512	458-527	56	1.58	1.07	0.0229	0.0155
	II	1416-1426		5	0.12	-	0.0125	
BigH 2	I	1640-1678	528-566	24	0.93	0.59	0.0244	0.0155
	II	1590-1637		14	0.38	-	0.0082	
Os 2	I	1545-1588	513-556	20	0.49	0.21	0.0113	
A.Schm 1	I	1510-1564	538-592	23	0.58	0.36	0.0107	0.0067
W.Schm 2		1511-1554	561-604	35	1.80	1.49	0.0419	0.0346
	II	1474-1508		24	0.84	-	0.0248	
Zola 2	I	1175-1228	337-390	49	1.37	1.04	0.0258	0.0196
	II	1146-1172		8	0.20	-	0.0078	
Zola 1	I	1192-1242	327-377	31	0.84	0.73	0.0167	0.0146
	II	1145-118		6	0.21	-	0.0042	
Foss 1	I	1646-1674	624-652	15	0.27	0.152	0.0104	0.0054
	II	1586-1640		17	0.32	-	0.0060	
W.Schm 1	I	1498-1558	536-596	41	1.66	1.22	0.0276	0.0203
	II	1447-1495		15	0.49	-	0.0103	
Snyd 2	I	1208-1246	348-400	29	0.87	0.48	0.0228	0.0126
	II	1153-1203		6	0.18	-	0.0036	
Kazm*1	I	1376-1420	465-509	10	0.44	0.174	0.010	0.0040
	II	1321-1373		15	0.31	-	0.0066	
Kirkm 1	I	1346-1397	435-486	46	1.16	0.81	0.0227	0.0159
Buck 1	I	1483-1531	473-520	46	1.59	1.39	0.0331	0.0289
	II	1422-1478		14	0.31	-	0.0056	
Guerra 2	I	1521-1549	501-529	24	0.83	0.34	0.0180	0.0074
George 2	I	1168-1213	281-326	43	0.83	0.22	0.0181	0.0048
	II	1104-1159		8	N.D			
Pariso	I	1548-1592	498-541	38	2.19	-	0.0497	
	II	1492-1540		19	0.72	-	0.0179	
Meiler 1	I	1530-1578	505-553	48	1.58	1.58	0.0329	0.0329

* Interval perforation 1321-1394 ft, including Objects I and II

<u>Second criterion.</u> To determine the filtration thickness, H_F, we determined the limited values W_G, m and S_G, from which we obtained the influx of gas into the existing production system. Table 2 shows how W_G, m and S_G, were determined, for more possible values.

Maximum values of the limited parameters correspond to the maximum values of W_G, m, and S_G in the intervals of perforation from where gas was extracted. In this way, the average values of W_G*, m*, and S_G*, are from productive sections of wells where gas was extracted, from layers with relatively low required parameters (Table 2). Maximum values of the limited parameters are $W_G* = 2.7\%$, $m* = 5.0\%$, and $S_G* = 54\%$. According to lithological classification, possible permeability for this rock is 1.3md. The probable value of the limited parameters taken from results of estimation of maximum W_G, m, S_G in the condition that for influx, the necessary minimum thickness of an object-collector is 5, 10, or 15 feet. From Table 2 we see that if the minimum thickness in the well is $\geq$ 10 ft, then probable values for the limited parameters are: W_G*=2.0%, $m*$=4.4%, and S_G*=45%. For these rocks, permeability is approximately 1md. The values calculated above do not contradict accepted ideas about conditions of productive formations that have influx of waterless gas and the filtration process can be described by Darcy's Law.

Table 2. Limited values of W_G, m and S_G, and more possible values.

Well Name	W_G * max/m, %	W_G * m (%)	W_G * m (%)	W_G * m (%)
		5ft	10ft	15ft
Kub 2	4.0/7.7	3.9/6.6	3.4/6.7	3.1/6.8 from 14ft
DLSP 10	3.5/6.3	3.5/7.0	3.2/6.7	2.8/6.2
Meiler 1	4.7/7.3	4.1/6.3	3.8/5.8	3.4/5.3 from 16ft
Foss 1	2.5/4.8	2.5/4.8	1.8/4.8	1.8/4.7
George 2	3.1/5.2	3.1/5.3	2.1/4.4	1.8/4.4
Buckm 2	5.6/8.2	4.6/7.1	4.5/6.2	4.4/6.2
DLFC 1	4.4/6.1	3.2/5.7	2.8/5.4	2.6/5.5
Os 2	4.0/6.1	3.2/5.8	3.1/5.8	2.1/5.1
Kirkm 1	3.7/6.4	2.8/6.3	3.2/6.1	2.8/6.3
E.Kazm 1	3.5/6.2	2.3/5.0	2.1/5.6	1.8/4.7
A.Schm 1	3.5/6.5	3.3/6.6	2.8/5.7	2.4/5.4
Min from Wgmfx	2.6/3.1-3.5	2.3/2.8-3.1	2.0/2.1	1.8/2.1
S_G *,%	53/60-54	46/50-45	51/48	=45
m,%	4.8-5.2	5.0/5.3	4.4/5.0	=4.4
W_G *	2.7	2.5/2.3	2.2/2.5	=2.0
Kmd	=1.3	=1.2	=1.05/1.2	=1.0

2. Estimation of capacity parameters of gas saturation in the Medina reservoir.

According to the log data of the 43 wells, we estimated the capacity parameters: effective thickness (H_N) and filtration thicknesses (H_F), linear gas reserves in the limits H_N and H_F respectively, L_Gi and $L_G$fi, and the concentration of the gas reserves on a unit basis (per foot of total thickness), respectively W_G□ and W_Gf□. These parameters are calculated according to the following formulas:

- Values of total line gas reserves for interval -L_Gi

  $$L_G i = \Sigma H_N i * W_G\, i$$

- Value of filtration line gas reserves – L_G fi

  $$L_G\, i = \Sigma\, H_F i * W_G\, i$$

- Concentration gas reserves on the unit total thickness H_O- W W_G □ and W_G f□

  W_G □ = L_Gi / H_O

  W_G f□ = $L_G$fi / H_O

Practice shows that the parameter W_G□, which is the concentration of gas reserves for total reservoir thickness by unit, is a more stable parameter that is commonly used because it enables an accurate evaluation of gas reserves by the volumetric method. Parameter Wgf□ is characterized by the variability of the concentration of filtration of gas reserves by space. Enumerated parameters, excluding H_F, for Object I, are shown in Table 1. Evaluation of filtration parameters was possible only for wells in which proper data was available. For Object II, the necessary data was absent: often this section does not have log data or other evaluations. Data analysis, shown in Table 1, demonstrates the following.

Objects I and II are very not homogenous in the distribution of total and filtration gas reserves by area of reservoir. Research of gas reservoirs shows that even for very big reservoirs with very high filtration-capacity characteristics, the ratio of maximum and minimum W_G□ is more than 5 (in the case that average reservoir permeability is approximately 100 md). For Object I, the distinction between the best well, Pariso 1, and the worst well, Kazmak 1, is the same (see Table 1), but the sizes of reservoir around the Pariso 1 is small. The biggest value W_Gf□ for this object is in the well W. Schmidt 2 (0.0346) and the smallest is in the well Kazmak 1 (0.004).

For Object II, the maximum value of W_G□ is in the well W. Schmidt 2 (0.0248), and the minimum is in the well DLSP 19 (0.0012). Significant variations of Wg□ and W_Gf by area indicate the high possibility that there are large sections of lithological blocks that have no gas-dynamical connection between them.

For the main Object I, the 18 wells in the DLSP group is more homogeneous. For this zone, value variation Wg□ is 0.0186-0.0351 with an average of 0.0293. The least homogeneous, by value W_G, is the zone around the southern wells Big Hill 1 and Kazmak 1. Object II is less homogenous than Object I. Approximate characteristics of gas reservoir in this Object were derived from the ratio of linear volumes in the Objects I and II, $X_{II} = Lg_{II}/Lg_{I}$, because data of layer's area are not defined. Results of this calculation are given in Table 3a.

Table 3a. The ratio of the gas reservoirs between Object II and Object 1 (X_{II}).

Well Name	X_{II}	Well Name	X_{II}
2DLSP	0.34	4DLSP	0.23
5DLSP	0.45	10DLSP	0.28
11DLSP	0.51	13DLSP	0.30
19DLSP	0.14	20DLSP	0.30
1DLFC	0.10	3DLFC	0.24
5DLFC	0.22	3Os	0.27
2BUCK	0.50	2Kubik	0.25
1 Kurn	0.24	1BNT	0.08
1 Bid Hill	0.42	2 W.Schm	0.65
2 Zola	0.15	1Zola	0.19
1 Foss	0.80	1 W.Schm	0.30
1 Kazm	1.14	1Buck	0.28
2 Snyd	0.20	1Pariso	0.31
15 DLSP	0.40	4 DLFC	0.18

From this data, it follows that lowest value of $X_{II} = 0.008$ in the well BNT 1. and the highest $X_{II} = 1.14$ in the well Kazmak 1. Value X_{II} for groups of wells that are close together are

Table 3b.

Wells	Range of XII	Average	Number of wells
DLSP	0.14-0.51	0.33	9
DLFC	0.10-0.24	0.18	4
BNT-Buck	0.08-0.50	0.29	3
Bid Hill-Os	0.24-0.43	0.30	5
Foss-Kazm	0.30-1.14	0.72	4
Zola-Snyder	0.15-0.20	0.18	3

For all wells, the average value for the Medina formation (28 wells) is XII = 0.30. Therefore, Object II can become an additional object for gas exploitation in some of the reservoirs zones. The decision about developing Object II can be made after log analysis in each well.

3. Peculiarities of the Medina reservoir structure according to hydrodynamic observations.

The amount of hydrodynamic observations in the productive wells is very limited. We have flow tests for three wells, completion reports for 18 wells, where flow and pressure have been recorded, and for 15 wells, the value of initial pressure data. Table 4 shows the results of permeability evaluation according to Dupuy's formula in the supposition that the wells were revealed completely.

For calculation of thicknesses, two values were used – H_N and H_F respectively, and possible minimum and maximum values for permeability were obtained. On Figures 1 and 2, permeability and volumetric gas saturation are compared. There is not enough data, but even from the data available (just 14 values), a system of double porosity of the Medina sandstone reservoir appears – porosity from pore space in the main gas-saturated volume, and also porosity created by cracks, faults, fractures, or other discontinuities in the earth. On Figures 1 and 2, it is shown that for low values, correlation between permeability and volumetric gas saturation exists as usual for granular rocks. At the same time, for permeability values higher than 10 md, there is no correlation. Therefore, according to the limited data, we can say the following about double porosity: gas-saturated low permeability block matrix (with permeability lower than 6md, averaging approximately 3md) and with added cracks into the matrix, not connected with porosity, but providing significantly increased permeability.

Table4. Permeability of Object I according to the initial gas dynamical test of production wells

Well Name	Initial Flow, Mcfd	Pro, PSI	ΔP, PSI	ΣH_N / ΣH_F, ft	Kn/Kf, md
1DLFC	790	500	38	36/32	14/15
2DLFC	957	540	30	53/-	17/-
3DLFC	1057	380	76	52/32	10/16
5DLFC	436	460	69	40/29	6/8
18DLSP	315	500	185	37/-	1.7/-
1Bid Hill	623	450	36	30/22	20/27
1BNT	486	480	80	56/40	3.5/5
1Buck	936	530	29	46/25	20/37
2Buck	276	530	38	36/36	6/6
1Kurn	301	570	43	42/38	4.5/5
2Os	322	530	48	20/16	10/12.5
3Os	164	520	41	42/32	3/4
2Kubik	79	450	41	33/29	2/2.5
1Ders	321	580	36	35/-	4.5/-

This conclusion corresponds to other data, which is shown below. Existing data of initial formation pressure (Pro) shows significant differences in Pro values in different parts of the reservoir. Measurements of Pro values varied in the interval 380PSI to 580PSI. To analyze the variations in these initial pressures, we evaluated the ratio of initial reservoir pressure (Pro) and hydrostatic pressure (αp) for two filtration models of the Medina reservoir:

1. The reservoir consists of separated blocks with no hydrodynamic connection between them or separated by layers where gas is filtering when the gradient pressure is greater than the initial (critical) pressure - Gg. For this model, the hydrostatic pressure, Pgd, was recorded at the middle point of the perforations, and the corresponding hydrostatic pressure is αP_1.

2. The reservoir is one hydrodynamic pool, hydrodynamically connected with water-saturated rocks. Accordingly, the initial reservoir pressure for all wells corresponds to the hydrodynamic pressure at the level of the gas-water contact (we corrected for both the vertical distance between the gas-water contact to the point of measurement and the density of the gas). Accordingly, we named the ratio between reservoir pressure and hydrostatic pressure, αP_2. In this variant, for the theoretical gas-water contact, the gas-saturated bed floor was taken from the well Foss 1, the lowest of all the considered wells. Results are shown in Table 5.

Table 5. Corresponding reservoir and hydrostatic pressures for the Medina reservoir.

Well Name	Perforation Interval	Pro, PSI	$\alpha P_1/\alpha P_2$	Initial Prod'n /ΣQ, MCF/dMMCF
8DLSP	1408-1445	450	0.73/0.63	315/30.2
10DLSP	1358-1394	480	0.80/0.67	546/69.5
13DLSP	1324-1364	450	0.77/0.63	386/60.1
18DLSP	1378-1420	500	0.82/0.70	315/58.7
1DLFC	1190-1238	500	0.95/0.70	790/75.5
2DLFC	1200-1248	540	1.02/076	957/78.7
3DLFC	1190-1238	380	0.72/0.53	1057/159.6
5DLFC	1231-1263	460	0.85/0.64	436/106.0
1BidH	1643-1676	450	0.62/0.62	623/44.2
1BNT	1447-1504	480	0.75/0.67	486/6.7
1Buck	1487-1528	530	0.81/0.74	936/24.4
2Buck	1498-1537	530	0.80/0.74	276/19.0
1Kurn	1570-1610	570	0.83/0.79	301/36.1
2Os	1548-1585	530	0.78/0.73	322/14.9
3Os	1543-1486	520	0.76/0.72	164/21.8
2 Kubik	1434-1467	451	0.71/0.63	79/8.0
1Ders	1503-1539	580	0.84/0.76	321/6.3
1Foss	1652-1672	535	0.75/0.74	-/11.6

From the calculations shown in Table 5, we conclude:

- The value of initial reservoir pressure in the most investigated wells is essentially lower than the hydrostatic pressure for both filtration reservoir models.
- In the drilled area, it appears that there are a number of gas-dynamic, isolated, lithological and tectonic blocks. For geological reasons, the blocks are evidently small sizes: it is practically impossible to find areas where two or more wells have constant initial pressures.

- In the closely situated wells, such as the DLSP and the DLFC wells for example, the pressure difference is not caused by some inaccuracy of measurement of reservoir pressure.

Hydrodynamic well isolation with anomalous low pressure indicates the high possibility of local escape of gas, depending on the existence of vertical cracks. The vertical drainage canals properly correspond to large values of total production, ΣQg, from the wells with lower initial formation pressure (See Table 5, Figure 4). As seen on Figure 4. the result is that for the last 20 years of exploration, wells located in zones of low formation pressure obtained maximum gas production. It is clear that registered on the Figure 4, correlation between ΣQg and Pro is complicated by possible detached blocks of different sizes, changing gas-production regimes etc. As previously discussed, this corresponds well to the model of double porosity, deduced from the comparison of permeability data and volumetric gas-saturation. The conclusion about the block structure of the Medina reservoir and the existence of faults or cracks is very important and needs to be checked very carefully.

4. Evaluation of the sizes of drainage zones by productive wells.

Existing well data for the last 20-year period and results of the processed log data enables us to evaluate of the sizes of drainage zones for productive wells – in the first place for the explanation of the character of exploitation and second, the degree of extraction from the reservoir. These evaluations were made as follows.

1. Evaluation of drainage volume (Vdr) was calculated according to the formula of material balance:

$$\Sigma Q = AVdr\,(Po/Zo - Pk/Zk)293/(273+t),$$

where ΣQ – total gas production from i well,
Vdr – drainage volume from I well,
Po – initial reservoir pressure,
Zo – initial coefficient overpressure,
Pk – final reservoir pressure (taken Pk=80PSI),
Zk – final coefficient overpressure;
t – average reservoir temperature;
A – scale coefficient taken for calculation.

2. Evaluation of drainage area (Sdr) and drainage radiuses (Rdr) were calculated for minimum (Sdr min, Rdr min) and maximum (Sdr max, Rdr max) variants:

$$Sdr\ min = Vdr/Lgn,\quad Rdr\ min = (Sdrmin/\square)^{0.5}$$
$$Sdr\ max = Vdr/Lgf,\quad Rdr\ max = (Sdr\ max/\square)^{0.5}$$

In the calculation of Sdr and Rdr, we assume that the drainage zone has a cylindrical form with the height, Lgn (ft). Calculation of drainage parameters is shown on Table 6. We note that these calculations allow us to presume that:

1. Pressure in the stripped gas-saturated rocks (intervals from which gas was extracted) in the drainage zone of each well depleted to 80psi, independent of individual well characteristic
2. In the drainage zones of the wells, reservoir characteristics remained constant over the whole area and equal to the characteristics that were established according to log data.
3. Gas does not migrate from parts of the reservoir that are not involved in the exploitation, and not included in evaluation linear gas reserves calculation.

Table 6. Calculated parameters of drainage zones for production wells.

Well	ΣQ, MCF	Pro, PSI	Vdr, MCF	Lgn/Lgf,ft	Sdr/Sdrm ax ac	Rdr/Rdr max,ft
3DLFC	159628	380	7505	1.28/1.06	135/163	1360/1550
5DLFC	105951	460	3735	1.11/0.92	77/94	1030/1140
1DLFC	95525	500	2947	0.92/0.80	73/80	1000/1050
2DLFC	78700	540	2188	1.39/1.21	36/41	700/710
10DLSP	69542	480	2290	0.89/0.59	59/89	900/1100

13DLSP	60188	450	2119	1.68/1.64	29/30	630/640
18DLSP	58739	500	1813	1.02/0.65	40/63	740/940
1 Big H.	44272	450	1590	0.93/0.59	47/62	800/930
1 Kurn	36171	570	970	1.48/1.33	15/16	440/470
8 DLSP	30234	450	1067	1.39/1.21	18/21	490/630
lBuck	24490	530	700	1.59/1.39	10/12	360/390
3 Os	21853	520	643	1.18/0.82	12/18	390/490
2 Buck	19028	530	544	1.39/1/39	9/9	34/36
2 Os	14951	530	428	0.49/0.21	24/38	570/710
1 Foss	11657	530	327	0.27/0.152	26/50	600/850
2 Kub	8033	450	289	1.08/0.74	7/9	300/340
1BNT	6700	480	219	1.58/1.07	3/5	200/250
1 Ders	6320	580	304	0.98/0.58	7/12	300/390

From Table 6, it follows that drainage parameters can practically define the total gas production and are characterized by very low rates of extraction compared to the total in-state gas of the reservoir. However, the significant variation of parameters complicates the use of average evaluations for characteristics of degree of exploitation of gas from the reservoir. In this connection average evaluations were made about the drainage parameters for 35 wells, using the correlation between ΣQ:Pro (Figure 4), the correlation between Vdr and ΣQg, and also the resulting correlation between Lgn and Lgf . Results of these evaluations are shown in Table 7. For this process of calculation, we selected 53 wells out of all the wells in the area.

Table 7. Evaluation of parameters for zones drainage for production wells.

Well Name	ΣQ, MCF	Vdr, MCF	Lgn/Lgf,ft	Sdrmin/Sdrmax,ac	Rdrmin/Rdrmax,ft
4 DLFC	64593	1740	2.18/2.18	18/18	500/500
2DLSP	71159	2550	1.40/1.30	42/45	750/800
3DLSP	53159	1830	1.38/1.20	30/35	630/690
4 DLSP	62842	2070	1.29/1.05	37/45	700/800
5DLSP	38733	1270	1.36/1.10	22/27	550/600
6 DLSP	57412	1975	1.62/1.62	28/28	600/600
7 DLSP	35344	1110	1.60/1.60	16/16	460/460
9 DLSP	73992	2360	1.60/1.60	34/34	680/680
11 DLSP	64971	2330	1.22/0.90	44/60	780/900
14 DLSP	61157	2200	1.86/1.86	2727	590/590
15 DLSP	51282	1840	1.79/1.79	24/24	560/560
16 DLSP	53872	1720	1.28/0.95	31/42	650/750
17 DLSP	65573	2090	1.65/1.65	29/29	620/620
19 DLSP	36577	1235	0.92/0.53	31/54	650/860
20 DLSP	78835	2630	1.15/0.80	53/76	850/1020
lMeiler	29579	2070	1.58/1.58	30/30	630/630
2 Guerra	25485	845	0.83/0.34	23/56	550/900
1 Kazm	14901	495	0.44/0.17	22/57	540/900

IKirkm	6516	175	1.16/0.81	3.5/5.0	200/250
lW.Schm	2279	60	1.62/1.62	<1	110/110
2Snyd	24330	830	0.87/0.48	22/40	540/740
lZola	29183	975	0.84/0.73	27/34	600/670
2 Zola	35320	1180	1.37/1.04	20/26	510/600
2 George	30565	1020	0.83/0.34	28/68	600/970
2Wozn	25328	780	-	15/23	440/550
lUrq	18909	580	-	11/17	370/470
lKlosn	11956	370	-	6/10	280/370
1 Gamm	11582	375		7/11	300/380
10s	51353	1700	-	47/62	800/920
1 Graue	35375	1170	-	26/38	590/710
1 Guerra	25929	860	-	57/41	750/900
1 Sharpe	12657	420	-	6/11	280/380
2Foss	7653	255	-	4/7	220/300
1 Ch-Sm	7554	250	-	4/7	220/300
4 Ch-Sm	14667	490	-	40/57	740/900
lFry	23018	770	-	15/23	460/550
3 Hers	37473	1280	-	29/43	620/750
4 Hers	51478	1720	-	40/56	740/890
5 Hers	64817	2160	-	64.778	950/1050

Comparing the radial sizes of different drainage zones show that for wells DLFC 1, 2, 3, and 5, maximum drainage volume (Table 6) often overlaps over each other. The capacity characteristic of the rock of Object II, in these wells only, is approximately equal to the average capacity for Object I. However, when gas exploitation began in each well, their reservoir pressures were different. For the well DLFC 3, which produces the most gas in the area, the initial pressure was the least of all parts of the reservoir involved in extraction (See Table 6). The calculated drainage radius of the enumerated wells suggests with a high probability that gas migration from distant parts of the reservoir with higher pressure.

According to the selected 53 wells, it is possible to make a square evaluation of the completeness of gas extraction by the coefficient of drainage: Kdr = Sdr / Sres, where S res – the area of the reservoir from which the drainage coefficient is calculated. The maximum drainage radius for all candidate wells is approximately equal to 1600 ft (Table 6), which is equal to half of the distance usually used in practice for the space between gas production wells. Accordingly, in the reservoir area, for the wells that were closer than 3200 ft, the borders of their zones was taken at 1600 feet from the point of each well's location. This same condition was widespread for older wells to prevent offsetting gas to other wells, if they were located in the overlapping zone.

Further, for all wells of overlapping zones, ΣSdr min and ΣSdr max have been calculated, using data from Tables 6 and 7. For one old well, the value Sdr=60 acres was accepted, corresponding to the average Sdr max for all new wells + 20 acres, where 20 acres is the root-mean-square deviation from average. In Table 8 is shown the results of the Kdr evaluation for 16 allocated zones and in the sum for all zones, including 53 new wells and 21 old wells. Calculations testify to the rather low drainage areas of the reservoir that is obviously caused by the small sizes of blocks comprising the reservoir.

Table 8. Sizes of drainage zones for group of productive wells.

Well area	Square, ac	Quantity of Wells New / Old	ΣSdr, ac max - min	Kdr,% max- min
Choate- Smith	235	2/0	64 - 44	0.27- 0.19
Fry 1-Zola 2	738	4/0	123- 84	0.17 -0.11
George 2	340	1/3	248- 208	0.73- 0.61
Hersee3-4	290	2/0	99 -69	0.34-0.24
Hersee 5	290	½	198 -184	0.68- 0.63
DLSP-DLFC	2950	22/3	1340 1095	0.45- 0.37
Wozniak-Urquhart	415	2/2	160 -146	0.38 -0.35
Bontragerl-Buckenmeyer 2	365	3/1	78- 75	0.17 0'15
Big Hill l-Ffammack 1	575	2/2	193 - 174	0.34- 0.30
Kurnik 1	415	1/1	76 - 75	0.18- 0.17
Guerral2-2	340	2/2	271 -213	0.80 0.63
Osuchal-3 Meiler	740	2/2	268 - 233	0.36 0.31
Kubik 2-Kirkman 1	850	¾	265- 257	0.31 -0.29
Foss2-Kazmarkl	480	2/0	64- 26	0.13- 0.05
Dersam 1-Schmidt	490	4/0	13 8	0.03 -0.02
Fossl	500	½	170- 146	0.30- 0.26
Total	10070	53/21	3323- 3035	0.33 -0.30

5. Discussion of results.

The lead analysis of data logs and the results of geological field data allows us to categorize the following features of the Medina formation, which characterize the filtration model and allow us to formulate recommendations on the optimization of its development.

1. Object I consists of low-porosity, gas-saturated sandstones (porosity in interval 4-11%; gas saturation 40-70%). Permeability of rocks in the interval is 1-20 md. Gas-saturated rocks, visibly, have the double porosity system: matrix with permeability 1-6 md, on which cracks are imposed, with permeability of more than 10 md. Object I is characterized by significant non-homogeneity in the drilled zone.

2. Gas is present in the Medina reservoir in the area above of Object I. Productive sediments are the same as the rocks in Object I, which are characterized by very thin layers of sand. The gas reserves of this part of the section account for approximately 30% of the reserves of gas in Object I. These sediments above Object I were drilled in one production well, Kazmak 1, where gas exploitation in this well was made jointly with Object I.

3. The initial reservoir pressure in Object I is essentially different in difference parts of the reservoir and in most wells, the pressure is significantly lower than the hydrostatic.

4. In the closely disposed (nearby) wells, there are significant differences in initial reservoir pressure, from 380 to 540 psi, with distances between wells of 1500 ft. These differences are caused by the local escape of gas from the reservoir through vertical filtration canals (faults).

5. In Object I, there is a significant correlation between the total gas production by a well and the well's initial reservoir pressure. The maximum gas production of any well was obtained from the zones where the initial reservoir pressure was the lowest.

6. The total gas production from the wells is defined by the existence of vertical faults or cracks and the existence of gas-saturated rocks with relatively higher capacity-filtration characteristics. Lower total gas production is caused by a lower quantity or degree of cracks in the rocks.

7. Geophysical characteristics and the functionality of a well indicates with a high degree of probability that well productivity is determined mostly by the number of cracks in the zone near the well's location. Probably, the cracks in the reservoir and the existence of filtration canals (faults) in the sediments above Object I (possibly they had permeability only during a period of tectonic activity) caused gas to escape prior to commercial gas exploration. The reservoir represents a set of blocks, between which there is no hydro-dynamical communication. Thus the level of total gas production is defined by the sizes of the blocks and the degree of faults.

8. If the represented model of the reservoir can be confirmed, then it will be possible to expect an important increase in gas extraction, after revealing the zones of development cracks and hydro-dynamically isolated blocks.

9. In several parts of the reservoir, it is prospective to begin exploiting Object II.

6. Conclusions.

1. The results of our analysis show that within this reservoir, there exists significant gas reservoirs not currently involved in exploitation.

2. Object I is characterized by block structures and the existence of local zones of intensive cracks.

3. It is expedient to use distance methods (satellite or aerospace imaging) to reveal cracks in the zones available for drilling and add these results to the existing information about the Object.

4. To directly check the hydrodynamic isolation of the reservoir and the volumes of gas not currently involved in drainage, we need to complete a hydrodynamic flow test of the well Pariso 1, still not perforated. The well is located in sufficiently favorable conditions. The works should include perforation and an open flow test after the well has been shut-in 5-10 days.

5. It is expedient to carry out repeated or secondary hydrodynamic tests for the with the object of preservation control of filtration canals, made by commercial hydro-fracturing. This is especially important in wells with lower initial reservoir pressure and relatively small total gas production. On the basis of this data, we may develop a program for increasing the gas recovery rate and completeness of its extraction from the reservoir, and drill additional new wells.

6. Recommendations for hydrojet slotting are favorable, including all wells in Table 1, plus other wells in the surrounding Counties (if opportunity arises). Priority wells are shown in Table 9, including sections of preference. Note that, when it is prospective to enter a section, completion of hydrodynamical testing is necessary.